System Personnel Training Drafting Team Meeting

Hosted by Orlando Utilities Commission

October 30, 2007 — 8 a.m. to 5 p.m. Eastern Daylight Time
October 31, 2007 — 8 a.m. to 4 p.m. Eastern Daylight Time

6113 Pershing Avenue
Orlando Fl 32822

Agenda

1) **Introductions**

   a) Antitrust & Administrative (**Attachment 1**)

   b) Review Meeting Objectives:

      i) Ensure all team members know what the Standards Committee expects of them

      ii) Draft responses to each comment submitted on the second posting of the Standard

      iii) Modify the standard based on discussion of comments submitted on the second posting of the standard

      iv) Draft a Standard Comment Form for the next posting

2) **Review Standards Committee Expectations** (**Attachment 2**)

3) **Review FERC Criteria for Approving Standards & 10 Benchmarks of Excellent Reliability Standards** (**Attachments 3 & 4**)

4) **Draft Responses to Comments** (**Attachment 5**)

5) **Modify Standard** (**Attachment 6**)

6) **Draft Comment Form** (**Attachment 7**)

7) **Summarize Action Items**

8) **Schedule Next Meeting**

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NERC Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

SPT SDT Meeting

Orlando, FL
October 30 & 31, 2007

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Topics

- Overview of Remaining Steps
- Expectations of SDT Members
- Drafting a Standard
  - Background Information
  - Introduction
  - Requirements, Violation Risk Factors, Time Horizons, & Measures
  - Compliance Elements
- Is Standard Ready to Post?
- Comment Forms
- Implementation Plan
- Field Testing

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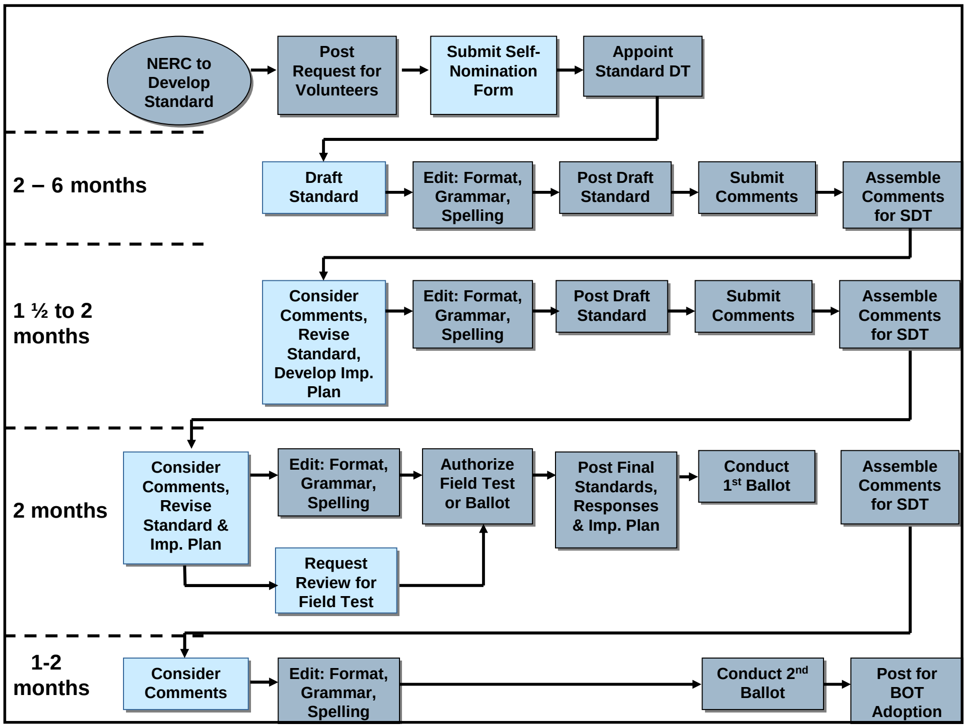

Expectations of SDT Members

- Produce a technically sound, complete standard that meets stakeholder approval and approval of regulatory authorities
- Produce a realistic implementation plan
- Preserve ‘open’ process

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Produce a Technically Sound Standard

- Standard must:
  - Have a technically sound basis for the proposed requirements
  - Have widespread stakeholder support to achieve approval (66.6%)
  - Include all required elements as described in the Reliability Standards Development Procedure
  - Address Factors FERC Considers

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Produce a Complete Standard

- Some elements developed by SDT
- Some elements developed by CEDT
- Works best if SDT and CEDT meet jointly
- Expect all elements of standard to work together
- Expect standard to be posted with all elements in a single document at least once

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Standard – Sections Developed by SDT

- **Title** (from SAR)
- **Purpose** (from SAR – can be abbreviated)
- **Applicability** (functional entities required to comply and any facility limits)
- **Proposed Effective Date** (when compliance is effective after regulatory approvals)
- **Requirements** (who must do what under what conditions for what outcome)
- **Violation Risk Factors** (impact to reliability of violating the requirement)
- **Time Horizon** (time frame available to mitigate a violation)
- **Measures** (what will be reviewed to determine if entity is compliant)

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Standard – Sections Developed by CEDT

- **Compliance Enforcement Authority** (what entity will be the monitor – either Regional Entity or ERO)
- **Compliance Monitoring Period & Reset Time Frame**
  - **(not applicable)**
- **Data Retention** (the data that must be kept and by what functional entities)
- **Compliance Monitoring & Enforcement Processes** (identify monitoring processes
- **Other Compliance Information** (identify any special information that the CEA needs)
- **Violation Severity Levels or VSLs** (tell how badly entity 'missed' being fully compliant with requirement or sub-requirement)

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FERC's Criteria for Approval

- **Purpose**
  - Achieves a specified reliability goal?
- **Applicability**
  - Applicable to owners, users, or operators of the bulk-power system
  - Applies throughout North American to the maximum extent achievable without favor
  - Costs considered for smaller entities but not expense of reliability
- **Requirements**
  - Provide technically sound method to achieve the goal
  - Clear, unambiguous as to who is required to do what
  - Achieve the reliability goal effectively and efficiently
  - Do not represent "lowest common denominator"

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FERC's Criteria for Approval

- **Measures**
  - Clear, objective measure for compliance
- **Violation Severity Levels**
  - Clear, understandable consequences & range of penalties
- **Implementation Plan**
  - Realistic
- **Other Considerations**
  - Cannot adversely impact competition or restrict grid
  - Evidence fair and open process was followed
  - Provides balance with other vital public interests

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FERC Directives – PER-005-0 Summary

- Identifies expectations of training for each job function
- Develops training programs tailored to each job function with consideration of individual training needs of personnel
- Expands Applicability section to include
  - Reliability Coordinators,
  - Local transmission control center operator personnel (as specified in the discussion),
  - Generator Operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System
  - Operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs or operating nomograms for real-time operations
- Uses Systematic Approach to Training (SAT) methodology in its development of new training programs and
- Includes use of simulators by Reliability Coordinators, Transmission Operators and Balancing Authorities that have operational control over a significant portion of load and generation

* Note that Reliability Standards Development Plan 2007 – 2009 indicates that the yellow highlighted items will be addressed in a separate standard.

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Produce Realistic Implementation Plan

- Consider time needed to become compliant with new requirements
  - Do entities need time to identify reliability-related tasks?
  - Do entities need time to identify training needs?
  - Do entities need time to develop training?
  - Do entities need time to implement training?

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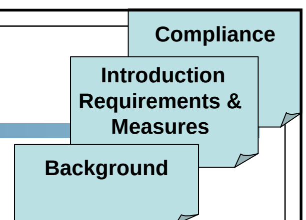
Preserve ‘Open’ Process

- ‘Standards under Development’ web site used for posting documents intended for stakeholder review and comment
  - Drafts of Standard
  - Comment Forms
  - Response to Comments
  - Implementation Plan
  - Field Test Results
- ‘Related Files’ section of each drafting team used for posting documents intended for use by team
  - Agendas and meeting notes (at least 5 days before/no more than 5 days after meeting)
- Meeting notices are posted on the ‘Meetings’ site
  - Anyone who registers may attend a meeting
  - Chair can limit the amount of time allocated to guests

Drafting a Standard



- Standard – Background Information
  - Standard Roadmap
  - Definitions
- Standard – Introduction, Requirements & Measures (SDT)
  - Introduction
  - Requirements (Violation Risk Factor) (Time Horizon)
  - Measures
- Standard – Compliance Elements (CEDT)
  - Compliance Enforcement Authority
  - Data Retention
  - Monitoring and Enforcement Processes
  - Other Compliance Information
  - Violation Severity Levels

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Standard – Background Info

Road-map

Standard Roadmap

- Removed when standard is adopted by BOT
- Shows where DT is in standard development progress
  - Lists steps completed
  - Lists steps to be completed with anticipated dates
  - Must be up to date when posted
- Schedule provided to SC in monthly progress reports

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Standard – Background Info

Definitions

Definitions

- Most new or revised standards do not include any new definitions
- Limit terms to those with **unique** definitions
  - If a term is in a collegiate dictionary, it doesn't need to be defined
- Don't include explanatory information in a definition
- Need stakeholder support for any new definition
- Capitalize defined terms when used in the standard

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Drafting a Standard – Introduction

- **Title** – System Personnel Training
- **Purpose** – from SAR (condense into a sentence or two) To ensure that System Operators performing real-time, reliability-related tasks on the North American Bulk Electric System are competent to perform those reliability related tasks. The competency of System Operators is critical to the reliability of the North American Bulk Electric System.
- **Applicability** – identifies the 'functional entities' that must comply with requirements & any exemptions or limitations on physical applicability
- **Proposed Effective Date** – can put 'to be determined' until final posting

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Applicability

- DT must decide – do requirements apply to:
  - All Reliability Coordinators?
  - All Balancing Authorities?
  - All Transmission Operators?
  - All "Delegates"?
- Look at Compliance Registration Criteria
- If any variations from default applicability, must provide a reliability-related reason

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Proposed Effective Date

- Can use 'to be determined' until last posting for comment – must match implementation plan
- Needs to identify the # of months needed to become compliant after applicable governmental approvals
- Needs to be the first day of the first month of a calendar quarter
- Needs to identify that some entities don't need to wait for regulatory approvals – their default is so many months after BOT adoption

  First day of first quarter, six months after applicable governmental approvals or in those jurisdictions where regulatory approval is not required the Reliability Standard becomes effective on the first quarter six months after BOT adoption.

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Drafting a Standard – Requirements, VRFs, Time Horizons, Measures

- Requirements identify mandatory performance or outcomes
- Each Requirement must have an associated Violation Risk Factor (VRF) and a Measure
- VRFs identify the reliability-related risk when a requirement is violated
- Time Horizons identify the time frame in which a violation could be mitigated

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What’s in a Requirement?

Tells - **Who** shall do **what** under what **conditions** for what **outcome**

R4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify the capabilities of each of its real-time System Operators to perform each assigned task on its list of company-specific BES reliability-related tasks.

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Requirements

- Written in ‘active voice’ (‘shall be’ is passive)
- Identify the responsible entity or entities
- Include a ‘shall’ statement
- Identify the ‘conditions’ under which the performance is required
- Identify the required performance or outcome
- Avoid:
  - ‘Negatives’
  - Ambiguous or subjective terms
  - ‘How’
- Must be measurable

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Violation Risk Factors (VRFs)

- Each Requirement must have an associated VRF
  - Sub-requirements **do not need individual VRFs** – if a sub-requirement has its own measure, then the sub-requirement must have its own VRF
- VRFs identify the reliability-related impact to the BES of violating a requirement
- VRFs are used to determine sanctions

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VRFs for Planning

Can a violation (**under the conditions anticipated by the preparations**) directly cause, contribute to, or place the BES at unacceptable risk of instability, separation, or cascading failures or hinder restoration?

If answer is . . .	Then VRF is . . .
Never	Lower
Possible but not likely	Medium
Yes	High

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VRFs for Operations

Can a violation directly cause, contribute to, or place the BES at unacceptable risk of instability, separation, or cascading failures?

If answer is . . .	Then VRF is . . .
Never	Lower
Possible but not likely	Medium
Yes	High

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What's the VRF?

R4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify the capabilities of each of its real-time System Operators to perform each assigned task on its list of company-specific BES reliability-related tasks. [Violation Risk Factor: Medium]

Can violation **directly** cause, contribute to, or place the BES at unacceptable risk of instability, separation, or a cascading failures?

- Yes – High
- Possible but not likely – Medium
- Never - Lower

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Time Horizons

- Identify how much time you'd have to mitigate a violation
- Used for determining sanctions
  - Bigger sanctions for real-time than for longer time horizons
- Each Requirement must have at least one Time Horizon
  - Some Requirements have multiple Time Horizons
  - If you assign VRFs to sub-requirements, the sub-requirement must have a Time Horizon

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Time Horizons

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

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What’s the Time Horizon?

R4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify the capabilities of each of its real-time System Operators to perform each assigned task on its list of company-specific BES reliability-related tasks. [Time Horizon: Long-term Planning]

Long-term Planning — planning horizon of one year or longer

Operations Planning — operating and resource plans from day-ahead up to and including seasonal

Same-day Operations — routine actions required within the timeframe of a day, but not real-time

Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system

Operations Assessment — follow-up evaluations and reporting of real time operations

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Measures

- Each Requirement must have at least one measure to identify what the Compliance Enforcement Authority will use to assess compliance
- If you assign VRFs to sub-requirements, then each sub-requirement must have an associated measure
- One measure can be used for multiple requirements or sub-requirements
- Avoid requiring specific types of evidence unless that is the **only** way to demonstrate compliance

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Sample Measure

R4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify the capabilities of each of its real-time System Operators to perform each assigned task on its list of company-specific BES reliability-related tasks. [Risk Factor: Medium] [Time Horizon: Long-term Planning]

M4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection verification of the capabilities for each real-time System Operator, as specified in R4.

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Avoid Use of Ambiguous Words

- Adequate
- Data
- Immediately
- Timely
- Detailed
- Sufficient
- Comprehensive
- As appropriate
- Coordinate

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Compliance Elements

- Compliance Enforcement Authority
- Data Retention
- Compliance Monitoring and Enforcement Processes
- Other
- Violation Severity Levels

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Standard – Compliance Elements

- **Compliance Enforcement Authority (CEA)** – what entity will be monitor – either Regional Entity or ERO
  - For most functional entities, the Regional Entity is the CEA
  - If requirements are assigned to the Regional Entity, then the ERO is the Compliance Monitor
  - If an RC is associated with a RE, then the RE cannot be the CEA

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Standard – Compliance Elements

- **Data Retention** – Identify what data must be kept and by what functional entities
  - For Responsible Entity – identify what must be kept and for how long with a reference to the associated measure (The RC shall keep evidence to show compliance with Measure 1 for 3 years)
  - For CEA - require that the retention of the last audit records and all requested and submitted subsequent audit records.

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Standard – Compliance Elements

- **Compliance Monitoring and Enforcement Processes:**
  - Compliance Audits
  - Self-Certifications
  - Spot Checking
  - Compliance Violation Investigations
  - Self-Reporting
  - Periodic Data Submittals
  - Exception Reporting
  - Complaints
- **Other Compliance Information** (Any special information that the CEA needs)
  - If performance is averaged over time, identify the minimum period in which a violation could occur
  - Identify whether there can be more than one violation monitoring per period

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Standard – Compliance Elements

- **Violation Severity Levels (VSLs)**
  - Tell how badly the entity 'missed' being fully compliant with a requirement or sub-requirement
- VSLs do not identify importance of a violation
- VSLs do not identify reliability-related impact of a violation
- Each requirement needs at least one violation severity level
  - If sub-requirements have individual VRFs, then there must be VSLs for the sub-requirements

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Standard – Compliance Elements

- **Lower:** mostly compliant with minor exceptions; closest to full compliance
- **Moderate:** mostly compliant with significant exceptions
- **High:** marginal performance or results
- **Severe:** poor performance or results; unacceptable performance

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Ready to Post?

- **General:**
  - Within scope of SAR?
  - Defined terms capitalized?
  - Ambiguous words removed?
  - Correct format?
- **Applicability:**
  - All functional entities responsible for complying with requirements are listed
  - If some entities or facilities are exempt, the exemption criteria is listed with a reliability-related reason

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Ready to Post?

- **Requirements:**
  - Each requirement written objectively and states what functional entity is responsible for doing what under what conditions and for what outcome
  - Each requirement includes a 'shall' statement
  - There is a VRF for each requirement
  - There is a Time Horizon for each requirement

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Ready to Post?

- **Measures**
  - At least one measure for each requirement
  - Each measure written objectively
  - If sub-requirements have VRFs, then each sub-requirement must be in a measure
- **Compliance Monitoring**
  - All sections completed
  - Compliance monitoring seems reasonable for reliability impact of non-compliance
  - Data retention meets needs of CEA without being overly burdensome to responsible entities

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Ready to Post?

- **Violation Severity Levels**
  - There is a VSL for each requirement
  - Where entities may not meet fully compliant with a requirement and partial compliance can be identified, there are multiple VSLs for that requirement
  - If sub-requirements have VRFs, then each sub-requirement has an associated VSL

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Ready to Post?

- Does standard meet FERC criteria for approval?
- Does standard meet NERC's benchmarks for reliability standards?

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Comment Forms

- Ask very pointed questions
- Ask only questions that will result in responses that you will use
- If you've made changes, ask for feedback
- If you've defined terms, ask for feedback on the terms
- Ask for feedback on implementation plan
- Ask if field testing is needed

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Responding to Comments

- Read through comments to get a 'sense' of stakeholders' reactions
- Consider & respond to every comment
  - Responses must be respectful
  - Responses should provide a justification
- Develop a 'summary response' to each question
- Make conforming changes to the standard
- Can't expand scope of SAR but can develop a standard that is smaller than the scope of the SAR

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Incorporating Suggested Changes

If the suggestion is submitted by	And the suggestion . . .	Then . . .	Ask stakeholders to . . .
Multiple entities in multiple regions	Does / may have technical merit	Incorporate suggestion	Confirm change
	Does not have obvious technical merits	Tell why suggestion lacks technical merit	
Single entity or by multiple entities in a single region	Does / may have technical merit	If widespread support anticipated, incorporate suggestion	Confirm change
		If widespread support not anticipated, don't incorporate	Indicate preference for suggestion
	Does not have obvious technical merits	Tell why suggestion lacks technical merit	

Weighing Comments

# signatures	# companies	# segments	# comments
1	1	1	1
5	1	1	1
8	1	3	3
12	12	1	12
12	3	3	??

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Implementation Plan

- Tells stakeholders how/when standard will be implemented and identifies:
  - Any prerequisites for implementation – such as another standard that needs to be implemented first
  - Any already approved standards that should be modified as a result of the proposed standards
  - Functions that must comply
  - When entities must be compliant (matches proposed effective date in standard)
  - Reasons for any recommended delay in implementation such as time to develop procedures, time to provide training, or to modify software

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Field Testing

- Ask stakeholders for their views
- Document drafting team's views
- Ask VP, Director of Compliance to send SC a recommendation on field testing compliance elements of standard
- SC makes final determination – may ask a tech committee to oversee field test

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Questions?

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FERC's Criteria for Approving Reliability Standards

As drafting teams begin their work, they should consider the following criteria used by FERC when determining whether to approve a reliability standard:

1. Must be designed to achieve a specified reliability goal
2. Must contain a technically sound method to achieve the goal
3. Must be applicable to owners, users, or operators of the bulk-power system, and not others
4. Must be clear and unambiguous as to what is required and who is required to comply
5. Must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation
6. Must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner
7. Should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost
8. Cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk-power system reliability
9. Costs to be considered for smaller entities but not at consequence of less than excellence in operating system reliability
10. Must be designed to apply throughout North American to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach
11. No undue negative effect on competition or restriction of the grid
12. Implementation time (balance of any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability)
13. Whether the reliability standard process was open and fair
14. Balance with other vital public interests
15. Reliability Standard not conflict with prior Commission Orders, tariffs, etc

The Ten Benchmarks of an Excellent Reliability Standard

1. **Applicability** — Each reliability standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted. Such functional classes include: reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning coordinators, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each reliability standard shall also identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area. As applicable, a standard may also identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 megawatts or greater, or transmission facilities energized at 200 kilovolts or greater.

2. **Purpose** — Each reliability standard shall have a clear statement of the purpose of the standard. The purpose shall describe how the standard contributes to the reliability of the bulk power system.

3. **Performance Requirements** — Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practice and the public interest. Each requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in the particular field.

6. **Completeness** — Reliability standards shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, the consequences of violating a standard are clearly known to the responsible entities.

8. **Clear Language** — Each reliability standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practice, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

Consistent Terminology — To the extent possible, reliability standards shall use a set of standard terms and definitions that are approved through the NERC reliability standards development procedure.

Consideration of Comments on 2nd Draft of System Personnel Training Standard (Project 2006-01)

The System Personnel Training Standard Drafting Team thank all commenters who submitted comments on the second draft of the standard. This standard was posted for a 30-day public comment period from August 15, 2007 through September 28, 2007. The drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were more than 43 sets of comments, including comments from 130 different people from more than 70 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending .

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

http://www.nerc.com/~filez/standards/System-Personnel-Training.html

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

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

The Industry Segments are:

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

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.												
2.	Bruce Fauvelle	Alberta Electricity System Operator		✓								
3.	William J. Smith	Allegheny Power	✓									
4.	Ken Goldsmith (G6)	ALTW										
5.	Jeffrey V. Hackman	Ameren	✓		✓		✓	✓				
6.	Thad K. Ness	American Electric Power	✓									
7.	Thad K. Ness	American Electric Power (AEP)	✓				✓	✓				
8.	Jason Shaver	American Transmission Co. (ATC)	✓									
9.	Mike Scott	Arizona Public Service	✓		✓							
10.	John Keller (G9)	Atlantic City Electric	✓									
11.	Warren Maxvill (G16)	Avista Utilities	✓		✓	✓	✓					
12.	Brian Tuck (G16)	Bonneville Power Administration	✓									
13.	Rod Byrnell (G16)	British Columbia TC (BCTC)										
14.	Thomas Fung	British Columbia TC (BCTC)		✓								
15.	Brent Kingsford	CAISO		✓								
16.	Eric Hudson (G16)	CAISO		✓								
17.	Brad Calhoun	CenterPoint Energy	✓									
18.	Alan Gale (G3)	City of Tallahassee					✓					
19.	Mark MacDonald (G14)	CLECO	✓		✓		✓					
20.	Danny McDaniel (G14)	CLECO	✓		✓		✓					
21.	Edwin Thompson (G7)	Con Edison	✓									
22.	Phillip Vavala	Delmarva Power	✓									
23.	Vic Davis (G9)	Delmarva Power	✓									
24.	Hank LaBean (G16)	DOPD										
25.	Brian Berkstresser (G14)	EDE	✓		✓		✓					
26.	John Bonner (G7)	Entergy Nuclear			✓							
27.	Edward J. Davis	Entergy Services, Inc.	✓									
28.	Will Franklin (G14)	Entergy Services, Inc. (Gen. &					✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
		Mkt.)										
29.	Kent Grammer	ERCOT		✓								✓
30.	Doug Hohlbaugh (G1)	FirstEnergy Corp.	✓		✓		✓	✓				
31.	Sam Ciccone (G1)	FirstEnergy Corp.	✓									
32.	Dave Folk (G1)	FirstEnergy Corp.	✓									
33.	John Reed (G1)	FirstEnergy Corp.	✓									
34.	John Martinez (G1)	FirstEnergy Corp.	✓									
35.	Jerry Sanicky (G1)	FirstEnergy Corp.	✓									
36.	Dan Dipasquale (G1)	FirstEnergy Corp.					✓					
37.	Jim Eckels (G5)	FirstEnergy Corp.	✓									
38.	Jeff Gooding (G3)	Florida Power & Light Co.	✓									
39.	Ed DeVarona (G3)	Florida Power & Light Co.	✓									
40.	Donna Howard (G3)	FRCC										✓
41.	Billy Lee	Garland Power & Light	✓		✓		✓					
42.	John Kerr (G14)	GRDA	✓		✓		✓					
43.	Joe Knight (G5) (G6)	Great River Energy										✓
44.	David Kiguel (G7)	Hydro One Networks	✓									
45.	Roger Champagne (I) (G7)	Hydro-Québec/TransÉnergie (HQT)	✓									
46.	Ron Falsetti (I) (G7)	IESO		✓								
47.	Brian Reich (G16)	IPCO										
48.	Kathleen Goodman (I) (G7)	ISO New England		✓								
49.	Mike Locke (G3)	Jacksonville Electric Authority			✓							
50.	Jim Cyrulewski (G5)	JDRJC Associates								✓		
51.	Michael Gammon (G14)	Kansas City Power & Light	✓		✓		✓					
52.	Jim Useldinger (G14)	Kansas City Power & Light	✓		✓		✓					
53.	Eric Ruskamp (G6)	Lincoln Electric System										✓
54.	Steve Rainwater	Lower Colorado River Authority	✓				✓	✓				
55.	Don Nelson (G7)	MA Department of Public Utilities									✓	
56.	Joseph DePoorter (I) (G5)	Madison Gas and Electric				✓						
57.	Robert Coish (G6)	Manitoba Hydro	✓		✓		✓	✓				
58.	Tom Mielnik (G6)	MEC										
59.	Jason L. Marshall (G5)	Midwest ISO Stakeholders		✓								
60.	Michael Brytowski (G6)	Midwest Reliability Organization										✓
61.	Terry Bilke (G6)	MISO										✓
62.	Carol Gerou (G6)	MP										✓
63.	Mike Rannali (G7)	National Grid	✓									
64.	Randy MacDonald (G7)	New Brunswick System Operator		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
65.	James Castle	New York ISO		✓								
66.	Ralph Rufrano (G7)	New York Power Authority	✓									
67.	Michael K. Wilkerson	NIPSCO	✓		✓			✓				
68.	Murale Gopinathan (G7)	Northeast Utilities	✓									
69.	Reza Rizvi (G7)	NPCC										✓
70.	Guy V. Zito (G7)	NPCC										✓
71.	Al Adamson (G7)	NY State Reliability Council										✓
72.	George Brady (G8)	Ohio Valley Electric Corp.	✓									
73.	Scott Cummingham (G8)	Ohio Valley Electric Corp.	✓									
74.	Robert Mattey (G8)	Ohio Valley Electric Corp.	✓									
75.	Don Hargrove (G14)	OKE&G	✓		✓		✓					
76.	Pete Kuebeck (G14)	OKE&G	✓		✓		✓					
77.	Brian Gooder (G7)	Ontario Power Generation Inc.					✓					
78.	Ed Seddon (G3)	Orlando Utilities Commission	✓									
79.	Ron Verraneault (G16)	PAC										
80.	Richard Kafka (G9)	Pepco Holdings, Inc. – Affiliates	✓									
81.	Kris Buchholz	PG&E (1)	✓									
82.	Lauri Jones (G16)	PG&E (2)										
83.	Alicia Daugherty (G10)	PJM		✓								
84.	Al DiCaprio (G10)	PJM		✓								
85.	Glen Boyle (G10)	PJM		✓								
86.	Ray Gross (G10)	PJM		✓								
87.	Mark Kuras (G10)	PJM		✓								
88.	Stephanie Monzon (G10)	PJM		✓								
89.	Tom Bowe (G10)	PJM		✓								
90.	Richard Krajewski (G16)	PNM										
91.	Dick Schwarz (G16)	PNSC										
92.	Valerie Hildebrand (G9)	Potomac Electric Power Company	✓									
93.	Rick Brock (G16)	PSC									✓	
94.	Sarah Lutterodt	Quality Training Systems								✓		
95.	William M. Hardy, Chr.	RCSDT										
96.	Jon Crook (G16)	Sacramento Municipal Utility District										
97.	Jim Fee	Sacramento Municipal Utility District	✓		✓	✓	✓			✓		
98.	Mike Pfeister	Salt River Project	✓		✓		✓	✓				
99.	Mike Gentry	Salt River Project										
100.	Scott Peterson	San Diego Gas & Electric Co.	✓		✓							

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
101.	Terry Blackwell (G11)	Santee Cooper	✓									
102.	Tom Abrams (G11)	Santee Cooper	✓									
103.	Glenn Stephens (G11)	Santee Cooper	✓									
104.	Rene' Free (G11)	Santee Cooper	✓									
105.	Kristi Boland (G11)	Santee Cooper	✓									
106.	Jim Peterson (G11)	Santee Cooper	✓									
107.	Wayne Ahl (G11)	Santee Cooper	✓									
108.	George Noller (G16)	SCE										
109.	George Noller	SCE	✓									
110.	Charles Wubenna (G3)	Seminole Electric Cooperative	✓									
111.	Marc Butts (G13)	Southern Company Services	✓									
112.	Roman Carter (G13)	Southern Company Services	✓									
113.	Jim Busbin (G13)	Southern Company Services	✓									
114.	J. T. Wood (G13)	Southern Company Services	✓									
115.	James Ford (G13)	Southern Company Services					✓					
116.	Fred Rains (G13)	Southern Company Services					✓					
117.	Robert Rhodes (G14)	Southwest Power Pool		✓								
118.	Kyle McMenamin (G14)	SPS	✓		✓		✓					
119.	Stephen Joseph (G3)	Tampa Electric Company	✓									
120.	Robert Eubank (G16)	Tri-State G&T	✓									
121.	Karl Bryan	U.S. Army Corps of Engineers					✓					
122.	Jim Haigh (G6)	WAPA										✓
123.	Howard Rulf	We Energies			✓	✓	✓					
124.	Ken Driggs (G16)	WECC										✓
125.	Eric Langhorst (G16)	WECC										✓
126.	Neal Balu (G6)	WPSR										
127.	Pam Oreschick (G6)	XCEL										✓

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – FirstEnergy Corp.
G2 – Florida Power & Light Co. (FPL)
G3 – Florida Reliability Coordinating Council (FRCC)
~~G4 – ISO/RTO Council~~
G5 – Midwest ISO Stakeholders
G6 – MRO Standards Review Committee (MRO SRC)
G7 – NPCC Reliability Standards Committee (NPCC RSC)
G8 – Ohio Valley Electric Corp. (OVEC)
G9 – Pepco Holdings, Inc. – Affiliates
G10 – PJM
G11 – Santee Cooper
G12 – SERC Operations Planning Subcommittee (SERC OPS)
G13 – Southern Company Services, Inc. (Southern Transmission)

G14 – SPP Operating Reliability Working Group (SPP ORWG)
G15 – Tennessee Valley Authority (TVA)
G16 – WECC Operations Training Subcommittee (WECC OTS)

Index to Questions, Comments, and Responses

1. Do you agree that it is reasonable to at least annually, assess the training needs for each system operator position by determining any mis-match between acceptable and actual performance capability? [R2]? If not, please explain in the comment area.

Summary Consideration:

Question #1			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		Yes, although as proposed it is unclear how that objective will be determined.
Response:			
Florida Power & Light	☑		I agree that it is reasonable to annually assess the training needs for each operator position (R-2) in relationship to the defined company-specific reliability-related tasks (R-1.1). However, the assessment requirement (R-2.1) based on a mis-match between acceptable and actual performance capability seems ambigious and leaves the measurement (M-2) of this requirement subjective and open to interpretation. What is an acceptable means of preforming this assessment? What can we expect from a compliance audit on how they will assess each entity? An acceptable criteria (i.e., Auditors Guide) for evaluating this mis-match needs to be provided.
Response:			
FRCC	☑	☑	FRCC agrees that it is reasonable to annually assess the training needs for each operator position (R-2) in relationship to the defined company-specific reliability-related tasks (R-1.1). However, the assessment requirement (R-2.1) based on a mis-match between acceptable and actual performance capability seems ambiguous and leaves the measurement (M-2) of this requirement subjective and open to interpretation. What is an acceptable means of performing this assessment? What can we expect from a compliance audit on how they will assess each entity? An acceptable criteria (i.e., Auditors Guide) for evaluating this mis-match needs to be provided. FRCC agrees it is reasonable for this assessment to include identification of training to perform new or revised tasks from the company-specific reliability related task list. (R-2.2.)
Response:			
LCRA		☑	You are simply asking too much of a large segment of this industry-those utilities that have a small, or nonexistent, training staff. Your goals are lofty, but NERC is completely out of touch with reality if it believes that the huge requirements of this standard can be

Question #1			
Commenter	**Yes**	**No**	**Comment**
			effectively managed by utlities such as mine that employ a training staff of one.
Response:			
NYISO		☑	Monitoring the mismatch between acceptable and actual performance is a continual process. If there is a mismatch in the expectation and performance of reliability-based tasks, such mismatches are addressed immediately based on reliability requirements. Failure to do so is to risk non-compliance with reliability standards. To mandate an annual performance evaluations solely for the purposes of training, when continual reliability-based performance evaluations must be conducted to maintain compliance with operational standards, would be redundant. R2 should be deleted as unnecessary, given R1 and the compliance requirements with all other NERC standards. R1 addresses training for existing and "new or revised tasks."
Response:			
OVEC		☑	How can the training needs of a position be determined based on performance capability of that position? A position has infinite capability while an individual does not have infinite capability. The requirement be revised to determine mis-match of acceptable and actual performance and leave the word capability out of the requirement.
Response:			
PHI		☑	Comment 1. PHI is not sure what is meant by this requirement. The language is confusing. We understand assessing the training needs of individuals and setting or identifying training requirements for positions but not training needs for positions. Could the drafting team clarify what it meant by this statement? Our concern extends to sub requirement 2.1 as well, because it uses the same confusing language. R2.2 which refers to new tasks or changes to existing tasks for each position is easier to understand. When the tasks for the position change, we should be aware of this and provide a mechanism for ensuring this new content is incorporated into the tasks or responsibilities of the position. Isn't this all that is really needed? Comment 2. Because we are not quite sure what the assessment involves we do not agree that an annual assessment is reasonable.
Response:			
SMUD		☑	Assessment should be every two years Need to clarify what is being assessed. Is this referring to the Job Task and Analysis or System Operator Training?

Question #1			
Commenter	**Yes**	**No**	**Comment**
			What tasks should be reviewed? Every task associated with each operating position? BES company specific reliability issues?
Response:			
APS		☑	The task list for each position should be reviewed annually for updates, and suggestions for training must be solicited from Leads and Supervisors in order to improve operator performance and keep the program current. But that's not what you said in this statement.
Response:			
Santee Cooper	☑		However, it is not clear from the Requirement or Measure what is necessary to have an acceptable assessment.
Response:			
Avista		☑	A yearly evaluation for each system operator is a very large burden for any organization. Initial training for system operators should address the required job skill knowledge and tasks required for acceptable performance capability. New job tasks are trained for and implimented as new systems, tools and job functions become necessary. The routine functions of the system operator position are not the issue and EOPS training and evaluation should take care of the rest.
Response:			
FirstEnergy	☑		
Entergy (1)	☑	☑	Our response depends on who, what, where, when, and how the authors mean with the statement - "assess the training needs for each system operator position". We agree that each employer should evaluate the performance and training needs of each employee, probably on an annual basis. If that is what the authors meant then we agree and we request the authors make that intent more clear in the standard itself. In addition, we are concerned about who evaluates and determines "acceptable performance" and "actual performance". We suggest the authors make it clear the employer makes that evaluation and determination, not some third party. Throughout this draft standard the authors use the term "System Operator position" to mean a job category and a physical person with no distinction between the two applications. Please make it obvious in each application whether the requirement applies to a job category or a physical person.
Response:			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Quality Training Systems			No comment.
TAL		☑	R2.1 does not appear "clear and unambiguous". How can a position have a mis-match between acceptable and actual performance? Is the intent to identify each operators deficiencies for each task every year? Or to identify new tasks (covered in R2.2)? If the answer is "to annually identify the mis-match between acceptable and actual performance a specific assesment must be done on every task that remains on the Attachment A (after modification per R1.1.)", then it is overly burdensome and is not required in the verbiage to R4, which only requires a one-time verification. However, it is reasonable to verify that the modified (per R1.1) Generic Task List remains current at least annually.
Response:			
Madison G&E		☑	It is unclear what "acceptable" is and what measurements can apply to it when it has not been defined. It is unclear whether this means for each job title or for each person that holds the system operator certificate. If it is for each job title (position), this is reasonable, however if it is each person, then it becomes overly cumbersome. If for each person, this is the responsibility of the registered entity to council and supervise its' operators. Or does it simpley mean that the System Operator position (tasks) in question has been reviewed and they meet the currect position responsibilities? How can this be measureable if there is no change in job tasks from year to year? Perhaps it should read "System Operator job task for each position shall be reviewed upon addition or removal of system operator job tasks".
Response:			
Entergy (2)	☑		It is unclear as to whether this is referring to the job category or each individual. This needs to be clarified. One can only infer that this is meant to design the training program for the job category and evaluate it annually for necessary changes. Consider adding a sub-requirement or within this requirement to indicate that measurable and observable criteria must also be developed along with each task identified (since "measureable and observable criteria" is a Measure of this Requirement).
Response:			
ERCOT	☑	☑	Should read "mismatch between the previoulsy developed task list and current and/or new task". "Performance capabilities" relates more to personnel that it does to positions.
Response:			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Southern	☑		
Allegheny Power		☑	There are a number of concerns with assessing the training needs of each system operator position in this standard. First, the function of assessing the performance of system operators should be covered by a separate Standard. Combining Training Requirements with Performance Standards causes confusion and creates a very voluminous standard. The purpose of three of the four requirements is assessment rather than training. Second, althought doing an annual assessment of each operators performance is a desirable goal, doing a measurement of each operators performance with each company specific BES reliablity-related task is over-burdensome if even possible.
Response:			
AEP	☑		R2.1 - Yes, as long as the interpretation and intent is truly "capability", but not for actual performance of every reliability task for which the position is responsible. Out of the possible 374 reliability tasks (Attachment A to the standard), some tasks may be rarely done, or may be done only during emergency or emergency training, such as annual restoration/black-start drills and simulation excersises. Some emergency tasks can be actually performed to gage performance, whereas other emergency tasks are more of a table-top simulation without actually performing the task. Operator performance may be based on satisfactorily completing the annual training to gain knowledge to know how, where and when to perform the task(s), foster acceptable "capability", but, not actually require performing the task(s) to achieve actual results. Based on this criteria, the standard's measurment and audit for R2.1 must allow for the "training and knowledge base for task performance", to be the measure or assessment of the "performance capability" of such emergency tasks. R2.1 could possibly be reworded as follows or in some other fashion to help ensure auditing procedures follow the intent (intent explained in the "Background Information" preceding these comment questions): ---- The assessment shall include identification of mismatches between acceptable and actual performance capability, and/or the identification of mismatches between the acceptable and actual knowledge base for performance capability, that need to be addressed for future training. -----
Response:			
ATC		☑	ATC believes that the annual analysis should be on the position of system operators not for each system operator.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Response:			
BCTC		☑	Requirement 1 in this draft of the standard requires a full blown job task analysis be completed for each company and to maintain the JTA. We cannot support this requirement at this time. The requirement also requires all training outside of NERC CE training to follow the SAT. We cannot support this beyond the NERC CE requirements at this time or to develop it over the next 36 months. We do not have the staff to complete this beyond NERC CE requirements at this time and believe we should be focusing on NERC CE requirements until we can comfortably follow the SAT for CE first. Requirement 2: We cannot support R2 if the assessment of the System Operator position goes beyond the NERC CE program requirements to meet and maintain NERC Certification.
Response:			
CAISO		☑	The CAISO agrees that an operator needs-assessment be done at least annually, the IRC supports continuous assessment of operator training needs. That said, the CAISO does not agree that a prescriptive standardized process is desirable or feasible. Performance evaluation is a corporate responsibility not a NERC standard. The CAISO would propose that this standard be refocused from a standard that requires a set annual needs-assessment, to a standard mandating a given number of hours of continuous training through NERC-accredited Training programs. Please refer to our comments in response to Question 11. Discussion: An operator training needs-assessment is not a requirement that can be developed easily. Having an industry-wide competency level lends itself to debates, possibly without an agreement, particularly given there is already an operator certification examination. A standard that leaves definition of competency to be developed by the individual responsible entities would subject to requirement to a "fill-in-the-blank" category, which FERC has stated must be eliminated. A fixed annual needs-assessment may devalue a continuous needs-assessment program. A fixed annual program by definition focuses on a one-time evaluation. With such fixed programs, organizations and operators may be more focused on performing and passing a given evaluation, then focusing on a comprehensive evaluation of individual needs - an evaluation that involves subjective analysis such as interpersonal skills under stress

Question #1			
Commenter	**Yes**	**No**	**Comment**
			evaluation. A fixed annual needs-assessment may be useful from an auditor perspective, but it does not reflect the varied undefined times that training occurs. To identify a 'need" an auditable test evaluation would require a standardized scoring system. Does a score of X% indicate a need for training? Indeed, how would a test identify in which area the training need exists? Requirement 2 imposes a subjective obligation of "acceptable" capability. R2.1 mandates that "mismatches" be identified. However, the draft standard does not identify a mismatch. Today, training is provided for all changes that a corporate entity believes needs training. Similarly, corporate entities may not even provide training on new tasks that are self-explanatory. R2.2 mandates the compliance entity identify which tasks fall in which category. That subjectivity is reasonable but it is not what one would consider an industry standard.
Response:			
CenterPoint		☑	R2 is confusing. Assessing the training requirements of a system operator position is different than assessing the training needs of an individual system operator. This requirement should be reworded to clarify what assessment is being required. A definition of the term “system operator position” should be added to the Glossary of Terms. Identification of company-specific system operator position tasks may be reasonable on an annual basis or whenever tasks are added or deleted; however, assessment of individual system operator training needs should be over a three year period to align with existing NERC System Operator Certification and Continuing Education Programs.
Response:			
NIPSCO		☑	The caveat here is that before the assessment takes place, the requirements of each specific operator need to be developed. This process commences with the job tasks for each position being identified and the standards being developed from the task lists. It is difficult to determine the mis-match between acceptable and actual performance when the standard does not exist. The only standards that we currently have are that the operators must complete their NERC certification, and each operator is required to obtain 32 EOP hours of annaul training and obtain up to 200 hours of CEH to maintain their certification. Once we have completed the initial qualification of all the system

Question #1			
Commenter	**Yes**	**No**	**Comment**
			operators, it would make more sense to tie the assessment to NERC recertification so that the assessment is done every three years.
Response:			
NPCC RCS		☑	Please define how to constitute acceptable and actual performance cabability and clarify the requirement. How will industry identify "mismatch". Is this requalification of system operators. The requirement doesn't seem measurable and crisp to audit for compliance. This requirement has a "fill in the blank" characteristic.
Response:			
PG&E (1)			The intent of this section is acceptable, however, the wording assumes a level of performance that may not be present. An assessment is made to identify gaps between the knowledge or skill level of the worker and the requirements of the job. The requirements of the job are identified as the past requirements and new requirements.
Response:			
PG&E (2)		☑	It is unclear as to whether the assessment is for the position or each operator in the position. The Standard should reflect the training needs, in relation to the defined company specific reliability related tasks, for each position and would then be updated as needed. If there were no changes to that position in regards to the defined company specific reliability related tasks in the previous year, the position would be reviewed and updated every three years. It is also unclear in R.2.1 as to the identification of mis-matches between acceptable and actual performance capability. What is acceptable to one company may not be to another and therefore is left open to interpretation in the measurement, M.2. How would this be assessed in either the readiness evaluation or a compliance audit?
Response:			
PJM		☑	PJM not only agrees that an operator needs-assessment be done at least annually, PJM supports continuous assessment of operator training needs. That said, PJM does not agree that a prescriptive standardized process is desirable or feasible. Performance evaluation is a corporate responsibility not a NERC standard. PJM proposes that this standard be refocused from a standard that requires a set annual needs-assessment, to a standard mandating a given number of hours of continuous training through NERC-accredited Training programs. Please refer to our comments in response to Question 11. Discussion:

Question #1			
Commenter	**Yes**	**No**	**Comment**
			An operator training needs-assessment is not a requirement that can be developed easily. Having an industry-wide competency level lends itself to debates, possibly without an agreement, particularly given there is already an operator certification examination. A standard that leaves definition of competency to be developed by the individual responsible entities would subject to requirement to a "fill-in-the-blank" category, which FERC has stated must be eliminated. A fixed annual needs-assessment may devalue a continuous needs-assessment program. A fixed annual program by definition focuses on a one-time evaluation. With such fixed programs, organizations and operators may be more focused on performing and passing a given evaluation, then focusing on a comprehensive evaluation of individual needs - an evaluation that involves subjective analysis such as interpersonal skills under stress evaluation. A fixed annual needs-assessment may be useful from an auditor perspective, but it does not reflect the varied undefined times that training occurs. To identify a 'need" an auditable test evaluation would require a standardized scoring system. Does a score of X% indicate a need for training? Indeed how would a test identify in which area is the training need exists? Requirement 2 imposes a subjective obligation of "acceptable" capability. R2.1 mandates that "mismatches" be identified. However, the draft standard does not identify a mismatch. Today, training is provided for all changes that a corporate entity believes needs training. Similarly, corporate entities may not even provide training on new tasks that are self-explanatory. R2.2 mandates the compliance entity identify which tasks fall in which category. That subjectivity is reasonable but it is not what one would consider an industry standard.
Response:			
SRP	☑		
SDG&E			
We Energies	☑		
Garland		☑	I believe that the training of system operators needs to be assessed, but Garland Power & Light is a small utility that has a training staff of one personnel that has many other duties as well to perform. The requirement is completely out of scope for resaonability.

Question #1			
Commenter	**Yes**	**No**	**Comment**
			This would place a huge budget burden on small utilities that are managed by City Councils.
Response:			
HQT		☑	Please define how to constitute acceptable and actual performance cabability and clarify the requirement. How will industry identify "mismatch". Is this requalification of system operators. The requirement doesn't seem measurable and crisp to audit for compliance. This requirement has a "fill in the blank" characteristic.
Response:			
IESO	☑	☑	We agree with the annual assessment of the training need. However, we feel the standard needs to have a requirement on the competency level (defined industry-wide or by individual responsible entities) in order to identify the mismatch between acceptable and actual performance capability. That said, this is not a requirement that can be developed easily. Having an industry-wide competency level lends itself to debates, possibly without an agreement, and given there is already a certification examination. Leaving it to be developed by the individual responsible entities would subject the requirement to a "fill-in-the-blank" category, which is to be eliminated. A simpler approach would be to require responsible entities to assess training needs on an annual basis, without specifying how, and develop an effective training program with an aim to enable operating personnel achieve the required skillset. In this case, the requirement will focus on the process (annually assessment) and the what (the training program), not the how (measuring the mismatch).
Response:			
ISO New England		☑	Please define how to constitute acceptable and actual performance cabability and clarify the requirement. How will industry identify "mismatch". Is this requalification of system operators? The requirement doesn't seem measurable and crisp to audit for compliance.
Response:			
Manitoba Hydro	☑	☑	Not clear on what system operator position means. In theory I agree but from a practical purpose this is not an easy task, especially for non-routine or emergency tasks without the aid of a simulator. While reference is made to the 737 pilot, simulators for the aircraft industry are far more developed than those for electrical systems. Walking through restoration plans and emergency procedures is one thing but it is quite another thing to put into practice. Is it being suggested that a comparison of acceptable to actual performance be made from the task on the BES task list.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Response:			
MISO Stakeholders		☑	We agree that it should be a requirement to annually assess and update a training plan for each system operator position and design training around these assessments. However, the choice of words is poor and we can't support a requirement that implies it is acceptable for a System Operator to fill a position in which he does not meet an acceptable performance level.
Response:			
MRO	☑	☑	There is a potential ambiguity that "each system operator position" could be interpreted as meaning "each person who performs each operator position". This is because of the use of the words "actual performance capability" which seems to refer to a person not a position. The MRO assumes what is meant is each position not each person. Please confirm. Perhaps wording could be clarified by inserting "(not person)" after the word "position". Suggest replacing "acceptable and actual performance capability" in R2 with "required and existing performance capability". The MRO agrees with R2 in concept but in practice this is not an easy task, especially for non-routine or emergency tasks which may be very difficult to simulate in training. While reference is made to the 737 pilot, simulators for the aircraft industry are far more developed than those for electrical systems. Walking through restoration plans and emergency procedures is one thing but it is quite another thing to in practice.
Response:			
SPP ORWG	☑		There was much confusion within our group as to whether this requirement is directed toward the position of System Operator or to the individual operator. Although we struggled with finding words to clarify the point, could the SDT take this back to the drawing board and attempt to make the distinction clearer?
Response:			
WECC OTS		☑	WECC OTS is unclear as to whether the assessment is for the position or each operator in the position. The Standard should reflect the training needs, in relation to the defined company specific reliability related tasks, for each position and would then be updated as needed. If there were no changes to that position in regards to the defined company specific reliability related tasks in the previous year, the position would be reviewed and updated every three years. It is also unclear in R.2.1 as to the identification of mis-matches between acceptable and actual performance capability. What is acceptable to one company may not be to another and therefore is left open to interpretation in the measurement, M.2. How would this be assessed in either the readiness evaluation or a compliance audit?

Question #1			
Commenter	**Yes**	**No**	**Comment**
Response:			

2. Requirement 3 requires entities to provide at least 32 hours annually of emergency operations and system restoration training. This requirement is also included in the System Restoration and Blackstart standard (Project 2006-03). To eliminate duplication of requirements, please comment on whether the requirement should be in the System Personnel Training Standard or in the System Restoration and Blackstart standard.

Summary Consideration:

Question #2	
Commenter	**Comment**
Ameren	Remove from SR&B include only in Training
Response:	
Florida Power & Light	I would like to see this requirement be removed from the System Restoration and Blackstart standards and to be placed only in the Personnel training standard.
Response:	
FRCC	FRCC recommends this requirement be removed from the System Restoration and Blackstart standard and be placed only in the Personnel training standard.
Response:	
LCRA	It should be contained in the Continuing Education Program.
Response:	
NYISO	This requirement that has no basis in a systematic approach to training, it should be removed from both locations. Thirty two hours is an indefensible, arbitrary, and capricious number. Please explain the justification for selecting 32 hours rather than 64, or 16?
Response:	
OVEC	The training requirements for system operators should all be in the same standard, namely the System Personnel Training Standard.
Response:	
PHI	The requirement to provide 32 hours of EOP training annually belongs in the Personnel Training Standard because as listed in Attachment B, it encompasses a slightly broader set of topics than Restoration and Blackstart. Other standards, in addition to the Blackstart standard (i.e. Cyber Security and BUCC) have also identified training requirements. PHI believes any required or mandated training deriving from another standard should be specifically identified in the Personnel Training Standard with a cross reference to the applicable standard for the details of the requirement. (i.e. personnel, topics, length, frequency of the training etc.) and whether it may be included in an individual's required 32 hours of EOP or would be in addition to that.
Response:	
SMUD	System Personnel Training Standard Only

Question #2	
Commenter	**Comment**
Response:	
APS	The System Personnel Training Standard only.
Response:	
Santee Cooper	All training requirements should be listed in this standard.
Response:	
Avista	The trend seems to be to place some kind of training requirement in everything (FERC NOPRS, NERC Standards and Regional Standards.) My opinion is that training requirements should all be in one place and I would prefer that to be PER-005.
Response:	
Entergy (1)	We suggest the training requirement R3 be in the training standard.
Response:	
FirstEnergy	FE believes it is appropriate to have this requirement reside within the PER-005 standard and that the requirement be removed from the proposed standards that are being developed within the Project 2006-03 work effort. It is our position that all requirements related to personnel training should reside within the PER suite of standards.
Response:	
Quality Training Systems	No comment.
TAL	Not only should this requirement should be in the System personnel Training Standard, a checklist should be made so that ALL training requirements are included in this standard. One example is the annual training on Cyber Security (CIP).
Response:	
Madison G&E	a) This requirement needs to be in "Personnel Performance, Training, and Qualifications" standard. In NERC's Reliability Standards Development Plan dated Nov 30, 2006, the Work Plan objective to support its Goal is to "Reorganize the standards more logically based on topic and remove redundancies". All NERC Training Requirements need to be within the Personnel Performance, Training, and Qualifications Standard's section. b) All required training that a NERC Standard directs any entity to do should be placed in its own NERC (training) Standard. The NERC Standard category "Personnel Performance, Training, and Qualifications" is established for this purpose. As stated in FERC Order 693, para. 1335, training requirements would not be in one "all inclusive standard". A better fit is to have many individual standards (that specify training requirements listed in Personnel Performance, Training, and Qualifications section of the NERC Standards) under the heading of "Personnel Performance, Training, and Qualifications". If a training requirement is imbedded in a non-"Personnel Performance, Training,

Question #2	
Commenter	**Comment**
	and Qualifications" standard, it will lead to possible shortfalls from an entity. c) This requirement should be in the Personnel Performance, Training, and Qualifications Standard, because it applies to training not specifically related to System Restoration or Blackstart (e.g. loss of primary control center, energy emergencies, etc.). d) In R3, it is stated "... 32 hours annually of emergency AND system restoration training." Does this mean 32 hours of both or a total of 32 hours? Since system restoration is a subset of Emergency Opertions Topics (attachment B), then the SDT should delete system restoration from R3. Either way the SDT needs to state what the proposed requirement will be.
Response:	
Entergy (2)	We recommend that the requirement remain in the training standard and be removed from the Blackstart Standard project. The training standard is the appropriate place for consolidating and delineating any training requirements.
Response:	
ERCOT	1) Should go in PER-005. 2) However, it is recommended that the 32 hour requirement be remove completely because the CEH program captures the intent of this requirement. Furthermore, the 32 hours of emergency training is tracked on a different schedule than CEH requirements and creates an additional and confusing set of record keeping processes. Record keeping can be simplified without reducing the level and quality of training with the additional benefit of removing the audit liability created by the need to track each operator's records on a different schedule.
Response:	
Southern	From a organizational perspective, it would be best to include emergency and restoration training in the System Personnel Training standard. This way, all training is in a central location and would prevent system operator trainers from searching throughout the approximately 117 standards to find the particular standards related to training.
Response:	
Allegheny Power	The 32 hours of emergency operations and system restoratio training should be located in the System Personnel Training Standard.
Response:	
AEP	This requirement definitely should only be in one standard. It is presently in the PER-002 standard as a 5-day training requirement, and therefore should be in the PER-005, since PER-002 is being retired. It would also help in audits of the standard, to have the training record auditing done with the PER training standard records rather than the EOP standards.

Question #2	
Commenter	**Comment**
	The new EOP-005-2 standard draft 1 does not directly refer to the 32 hours or 5 days of emergency training. R9 of this EOP-005-2 draft does refer to the emergency operating topics, but does not specify annual training or the 5 day (32 hour) requirement, as does the present PER-002-0 standard.
Response:	
ATC	It's our position that all training related requirements should be in PER standards. The SDT should review all NERC standards and move other training specific requirements into this standard.
Response:	
BCTC	All Reliability related training required in a standard should be listed in the PER Standards. There should only be one place to see where Reliability required training to meet standards are listed.
Response:	
CAISO	The CAISO would prefer that all training comments are contained within the training standards.
Response:	
CenterPoint	The requirement should be in the System Personnel Training Standard. Further, any training requirements should be grouped into training standards. When necessary, other standards should reference the appropriate training standard for any specific requirements.
Response:	
NIPSCO	The 32 hour requirement is not currently included in Project 2006-03. This information should be included in the training document. The System Restoration and Blackstart standard should reference the training document when talking about frequency of training and content, that way the training document would contain all pertinent training data including frequency of testing and testing requirements.
Response:	
NPCC RCS	The 32 hour emergency training requirement belongs in the personnel training standard. Please provide the basis for the 32 hour requirement.
Response:	
PG&E (1)	If the number of hours of training are going to be in either standard, it should be in PER-005 only; however, the training areas is what should be specified and the number of hours left to the responsible party.
Response:	
PG&E (2)	The NERC System Personnel Training Standards as the repository for all training identified in the standards and therefore recommends this requirement not be duplicated in the System Restoration and Blackstart standard.
Response:	
PJM	It is not important which standard includes the subject requirement. Either way, the same entities will be mandated to comply. What is important is that one or the other be removed. If required to choose,

Question #2	
Commenter	**Comment**
	PJM would suggest including all requirements in the Training standards.
Response:	
SRP	This requirement should be in a PER standard. Ideally any requirement for training should be in a PER standard.
Response:	
SDG&E	The 32 hour training requirement should be in the System Restoration plan. PER-005 is really focused on what should be in a training program.
Response:	
We Energies	Training requirements should only be in training standards.
Response:	
Garland	It should be contained in the System Restoration and Blackstart standard.
Response:	
HQT	The 32 hour emergency training requirement belongs in the Personnel Training Standard. Please provide the basis for the 32 hour requirement.
Response:	
IESO	Training requirements should always be covered by one standard. This avoids duplication of requirements and lends clarity to the scope of the standard under consideration. On this basis, we feel that the 32 hours emergency training requirement should be covered in this standard since this standard deals with all aspects of training. Further, the standard on System Restoration and Blackstart has a narrower scope as compared to PER-005 - Restoration and Blackstart scenarios only - and may not cover all the emergency scenarios.
Response:	
ISO New England	The 32 hour emergency training requirement belongs in the personnel training standard. Please provide the basis for the 32 hour requirement. Is this in addition to the NERC Certification requirements? How does this Standard fit into the existing NERC Certification requirements?
Response:	
Manitoba Hydro	Should be part of the system personnel training standard. Anything related to training should be found in these standards.
Response:	
MISO Stakeholders	We don't think it matters which standard as long as it is in only one. It should be removed from the standard that is further behind in the process to minimize any schedule impacts. In relation to this annual training requirement, we recommend striking the second paragraph under section 2.4.3 of the Severe violation level. The first paragraph should cover all situations since 32 hours of training were provided or they weren't. If the 32 hours have not been met, the annual requirement has not been met.

Question #2	
Commenter	**Comment**
Response:	
MRO	Should be part of the system personnel training standard. Anything related to training should be found in these standards. Might be helpful to have a reference in the blackstart standard like "see personnel training standard for specific training requirements".
Response:	
SPP ORWG	The 32-hour annual training requirement for emergency operations and system restoration belongs in PER-005-2. All training requirements should be consolidated within the System Personnel standards.
Response:	
WECC OTS	WECC OTS views the NERC System Personnel Training Standards as the repository for all training identified in the standards and therefore recommends this requirement not be duplicated in the System Restoration and Blackstart standard.
Response:	

3. As stated in the approved SAR for this standard, do you agree that there should be a requirement to perform an assessment of the capabilities of each real-time System Operator to perform each assigned task that is on its list of company-specific reliability-related tasks? [R4] If not, please explain in the comment area.

Summary Consideration:

Question #3			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑	☑	Yes an assessment is important. No, the standard as written is not defined with time parameters and is unachievable.
Response:			
Florida Power & Light		☑	The standard as written, does not define a time frame for the assessment (R-4). I feel that this assessment is not achievable and is unrealistic due to the time burden involved. Clarification needs to be given as to the time frame when this evaluation is to be given.
Response:			
FRCC		☑	The standard as written, does not define a time frame for the assessment (R-4). The FRCC feels that this assessment is not achievable and is unrealistic due to the time burden involved. Clarification needs to be given as to the time frame when this evaluation is to be given.
Response:			
LCRA		☑	See #1 above. It is simply too much for smaller entities to handle. Has anyone in the group that developed this standard polled the industry to see what kind of resources are available to support it? If not, then you have no idea of whether or not it is feasible.
Response:			
NYISO		☑	Orientation training is provided in a systematic approach to assume the task. Reinforcement training of the key reliability tasks is an ongoing aspect of a systematic approach to training. Addressing gaps between expectations and actual performance is driven by reliability requirements, not training program structure. Annual testing of all staff, on all possible tasks, is a waste of training effort and operator time. R4 should be deleted as unnecessary, given R1 and the compliance requirements with all other NERC standards.
Response:			
OVEC		☑	This requirement is not necessary for several reasons. The ability to only perform individual tasks does not give a good indication of an operator's performance to manage

Question #3			
Commenter	**Yes**	**No**	**Comment**
			and execute reliable operation of the Bulk Electric System during critical times when multiple tasks must be performed in rapid succession...working under pressure. The performance of an operator in a pressure situation would provide a better measure of an operator's performance rather than assessing capabilities to execute individual tasks. With only assessing individual tasks, the big picture of an operator's performance to reliably operate the Bulk Electric System is not adequately determined. Also, the performance of individual system operators is already evaluated through a performance review process and training evaluations are a part of that process. In order to demonstrate compliance with this requirement, would these performance reviews need to be made availabe to compliance auditors? Allowing auditors to view the performance reviews would seem to violate privacy and confidentiality laws and would necessitate the involvement of the human resources department in the compliance process. If the human resources department were not involved in the process then a separate process would need to be duplicated in a "sanitized" manner for inspection by the compliance auditors. This duplication would be redundant and inefficient.
Response:			
PHI	☑		The requirement does not specify a time period. As stated, this would be a one-time check to determine that each operator can perform the assigned tasks and PHI would expect that we could complete that assessment over a period of time. If that is the case PHI agrees.
Response:			
SMUD	☑		We assume this is a one time evaluation of operating personnel on each assigned task that is on its list of company-specific reliability-related tasks. Subsequent evaluations should be at the discretion of the system operator's management.
Response:			
APS		☑	Experienced NERC-certified personnel may be hired as operators, and some NERC-certified incumbents have 25-30 years experience. It would certainly be a waste of resources to assess these personnel's knowledge, skill, and attitude and then send these personnel through weeks of Initial Training and the myriad of exams involved. There should be a "grand-fathering" provision for experienced personnel, such as a exemption based on observation of job performance.
Response:			
Santee Cooper	☑		Yes, assuming this is a one-time verification until the reliability related tasks change.
Response:			

Question #3			
Commenter	**Yes**	**No**	**Comment**
Avista		☑	Again, a huge burden on every organization. It is not the routine operating tasks that cause system outages. System Operators need to be evaluated on their knowledge of tasks that are required when the BES is operating with little or no margins, either voltage, reactive or thermal. System operators also need to be tested to determine if they can recognize when their system is at it's operating limits, not the periods when adaquate reserves more than compensate for sloppy operating!
Response:			
FirstEnergy	☑		We agree that there should be some assessment of the effectiveness related to knowledge and skills learned during training being transferred to work place performance. However, upon reviewing R4, the measures associated with R4, and the VSL aimed at R4, it is unclear what the standard's expectations are related to this requirement.
Response:			
Entergy (1)	☑	☑	Our response depend on who, what, where, when, and how the authors mean with the statement - "assess the training needs for each system operator position". We agree that each employer should evaluate the performance and training needs of each employee, probably on an annual basis. If that is what the authors meant then we agree and we request the authors make that intent more clear in the standard itself. In addition, we are concerned about who evaluates and determines "acceptable performance" and "actual performance". We suggest the authors make it clear the employer makes that evaluation and determination, not some third party.
Response:			
Quality Training Systems			No comment.
TAL		☑	The verification of satisfactory performance of "each assigned task" is overly burdensome. Although, since this is a one-time verification only per R4, I can live with it. If I have to verify each task for each operator every year, it is way overboard. Who determines if my verification is adequate? Is this my call, the RA team or the Compliance Audit? If I only have to satisfy myself, it is okay.
Response:			
Madison G&E		☑	a) It is unclear whether this means for each job title or for each person that holds the system operator certificate. If it is for each job title (position), this is reasonable,

Question #3			
Commenter	**Yes**	**No**	**Comment**
			however if it is each person, then it becomes overly cumbersome. Routine tasks are currently monitored by the System Operator's Supervisor as part of the Supervisor's on-going evaluation of the System Operator's job performance. Job performance evaluation is a normal part of supervision and is utilized to determine compensation levels, retain quality personnel and administer the promotion process. Requiring a formal test or evaluation of tasks performed on a routine basis will trivialize the assessment process and encourage rubber-stamp approval to sign off on each task. System Operators should only be required to formally demonstrate competence in performing non-routine tasks which are performed on an infrequent basis. Or does it simply mean that the System Operator position (tasks) in question has been reviewed and they meet the correct position responsibilities? b) As a measurable requirement, this becomes too cumbersome (if for each system operator). As a business practice, it is good, but some of the tasks (i.e. communication with the RC) are performed regularly and to have to document each task for each operator would be overly burdensome.
Response:			
Entergy (2)	☑		Is this meant to be a one time assessment? If so, then we agree since attempting to do this every year would be unreasonable. If it is mean to be recurring, then consider adding the requirement of a periodic assessment of a sample of tasks on an ongoing basis within the entity's own training program.
Response:			
ERCOT	☑	☑	It should be more specific in that there should be a task list for each position and not one list that covers multiple positions. Example: Companies with specialize positions should have a task list for each position. Auditors will apply a broad based task list to specialized positions and create findings stating that each position should be able to perform all tasks on the general list. Also, the Standard should clearly state that this is a one-time assessment for each system operator and their respective position. It should take into account prior work history, training, qualifications and certifications from previous employers when assessments are made.
Response:			
Southern	☑		
Allegheny Power		☑	As stated in the comments provided to question 1, this is a desirable goal. However,

Question #3			
Commenter	**Yes**	**No**	**Comment**
			there are several issues that make the described assessment problematic. Many of the company-specific reliability-related tasks are very difficult to measure and some are not measureable. The time and manpower required to conduct the measurement of all assigned tasks is overly burdensome and unreasonable.
Response:			
AEP	☑	☑	Yes, with the requirement focus on "capabilities" to perform, and with the objective being to qualify the operator for the journey operating level of their operating position during their initial/progression training. (See the comments in Question 1 above) Yes, but the revision to existing training curriculums/resources, development of new resources, development of performance evaluation methods/tools, and on-going training assessment of new operators, will be essential for most transmission operating entities to comply with this requirement. This standard will therefore require a significant increase in training & development staff to comply, thus placing greater financial burden on the entities. However, we feel that how the assessment of each individual operator is conducted should be left up to the operating entity. As a part of an annual review system operators are felt to be qualified then and that should be sufficient to determine capabilities of an operator. If a new job task is implemented during that year then it is felt that the necessary training for that task should be given based on whatever method the specific entity feels meets that requirement.
Response:			
ATC	☑		
BCTC		☑	We cannot support R4 if the System Operator performance evaluation goes beyond the NERC CE program requirements to meet and maintain NERC Certification.
Response:			
CAISO		☑	If there were a possibility of developing and quantifying a viable level of competency, then the CAISO would support such a requirement. However, the CAISO believes that the determination of this competency level and assessment of the mismatch would be troublesome and likely not measurable. The idea of entity-identified task lists is the antithesis of the word standard. The question of training is paramount to everyone. The issue raised here is whether or not it is sensible to write an Industry Training standard. Assessing the capabilities of a given

Question #3			
Commenter	**Yes**	**No**	**Comment**
			System Operator is an art not a science. To mandate such a art can (and likely will) result in entities being tied up in labor hearings for a long period of time debating whether or not the operator's 'capability level' is effectively measured by the NERC standard. Requirement 4 does not provide any quantifiable measure for identifying an operator's capabilities. Picking and choosing from a list makes this requirement even more subjective then a NERC-wide standard should be.
Response:			
CenterPoint		☑	R4 is duplicative because the NERC System Operator Certification Program already certifies the competency of system operators. A revised generic task list (Attachment A) could be used to develop specific courses to form the curriculum for emergency operations and reliability related topics within existing NERC training programs. The Continuing Education Program already assesses the courses before it grants Continuing Education Hours used for recertification. Likewise, a revised generic task list could could be used for the Continuing Education Program's curriculum.
Response:			
NIPSCO	☑		This assessment should be part of the initial qualification effort, before the individual fills the position of system operator. The assessment should then take place every three years in conjunction with NERC re-certification. An annual assessment of each assigned task would be administratively arduous.
Response:			
NPCC RCS	☑	☑	We agree with this principle however please clarify how you propose to execute and measure this requirement.
Response:			
PG&E (1)	☑		
Response:			
PG&E (2)		☑	The standard in its current language does not define how each task is to be assessed and documented. For instance would a check off sheet with the identified company-specific reliability related tasks be adequate? If a check off sheet were utilized, would this assessment be considered an annual process or is a one-time verification acceptable? What is the benefit to the operator in assessing each task? Do the tasks identify whether they will be performed as a team or individually and under normal or emergency conditions? Capabilities of an operator are a subjective interpretation by each company and measure (M.4) is left open to a wide interpretation by the evaluators and auditors. How would this be assessed in either the readiness evaluation or a compliance audit? If companies are following the standard to provide annual training, then the

Question #3			
Commenter	**Yes**	**No**	**Comment**
			assessments for each task would at times be duplication of the annual and on going training and therefore create additional work for a trainer.
Response:			
PJM		☑	If there were a possibility of developing and quantifying a viable level of competency, then PJM would support such a requirement. However, PJM believes that the determination of this competency level and assessment of the mismatch would be troublesome and likely not measurable. The idea of entity-identified task lists is the antithesis of the word standard. The question of training is paramount to everyone. The issue raised here is whether or not it is sensible to write an Industry Training standard. Assessing the capabilities of a given System Operator is an art not a science. To mandate such a art can (and likely will) result in entities being tied up in labor hearings for a long period of time debating whether or not the operator's 'capability level' is effectively measured by the NERC standard. Requirement 4 does not provide any quantifiable measure for identifying an operator's capabilities. Picking and choosing from a list makes this requirement even more subjective then a NERC-wide standard should be.
Response:			
SRP	☑		R4 is OK as written. It appears to allow for various methods of verification of capabilities such as observed actual performance, observed performance using simulation tools, and testing. This should work given the various task frequency and various levels of criticality.
Response:			
SDG&E		☑	It may be appropriate to perform an assessment, but the standard is getting over-prescriptive to require giving an assessment on a line by line basis. The assessment should be more global in nature regarding the general level of competency of the operator to perform the job functions.
Response:			
We Energies	☑		Yes as long as this will not be an annual requirement. There will be tasks that need to be assessed very infrequently.
Response:			
Garland		☑	See #1 above. It is too large of a burden on small utilities. The requirements should be modified for practicality and still accomplish the goal.
Response:			
HQT	☑	☑	We agree with the principle. However, please specify how you propose to to execute

Question #3			
Commenter	**Yes**	**No**	**Comment**
			and measure this requirement.
Response:			
IESO	☑	☑	The key attribute here is "assessment of the capabilities". As noted in our comments to Q1, above, while we do not disagree with developing a requirement for establishing the competency level for system personnel to perform the assigned tasks, the determination of this competency level and assessment of the mismatch would be troublesome and likely not measurable.
Response:			
ISO New England	☑	☑	We agree with this principle however please clarify how you propose to execute and measure this requirement.
Response:			
Manitoba Hydro	☑	☑	In theory I agree but from a practical purpose this is not easy. My real concern is who would be doing the evaluation. Besides being a burden on many utilities, as some utilities will maintain a narrow list of BES tasks so that they could comply. I am unsure whether or not each utility would treat the evaluation consistently. In some companies, supervisors work along side the system operators and may just give the evaluation a cursory effort. This would do nothing to improve training.
Response:			
MISO Stakeholders		☑	Each operator should have an annual plan that includes a combination of training based on job tasks, simulation, and classroom knowledge-based training. There may be hundreds of tasks in an entities JTA. It is unnecessary and administratively burdensome to require an assessment each year against each task.
Response:			
MRO	☑	☑	In R4 it isn't clear how often the Operator's capabilities must be assessed. There is a mismatch between Question 3 and R4. Question 3 uses the words "perform an assessment" whereas R4 uses the word "verify". An assessment is an estimate whereas to verify is to actually test. Perhaps R4 should use "assess" rather than "verify". In theory MRO agrees with R4 but from a practical point of view this is significant overkill. MRO Operators are already required obtain NERC certification. There is also the NERC Reliability Readiness Evaluation and Improvement Program. In addition, compliance to many other real time standards test the capabilities of the positions every day. How can the standard ensure that the assessment is being done consistently from company to company depending on who actually does the assessment and how complete or accurate each company's specific BES task list is? For example, some utilities may maintain a narrow list of BES tasks so that they could more easily comply. Would each utility treat

Question #3			
Commenter	**Yes**	**No**	**Comment**
			the evaluation consistently? In some companies, supervisors work along side the system operators and may just give the evaluation a cursory effort. This would do nothing to improve training. Do all tasks have to be assessed annually? Wording seems to be flawed in that every operator has to be varified on every task before they can operate. This does not seem to recognize that operators require actual operating experience to aquire capability in all tasks. In general R4 adds an excessive and and burdensome level of bureaucracy.
Response:			
SPP ORWG	☑		We can concur with this requirement providing the assessment process does not become burdensome on the entity providing the assessment. A one-time assessment, while not burdensome of itself, may be inadequate to ensure continued operator performance. On the other hand, annual assessments would require an excessive amount of administrative time. A possible solution could be to allow company-specific assessment criteria such as being proposed for performance criteria.
Response:			
WECC OTS		☑	WECC OTS feels the standard in its current language does not define how each task is to be assessed and documented. For instance would a check off sheet with the identified company-specific reliability related tasks be adequate? If a check-off sheet were utilized, would this assessment be considered an annual process or is a one time verification acceptable? What is the benefit to the operator in assessing each task? Do the tasks identify whether they will be performed as a team or individually and under normal or emergency conditions? Capabilities of an operator are a subjective interpretation by each company and measure (M.4) is left open to a wide interpretation by the evaluators and auditors. How would this be assessed in either the readiness evaluation or a compliance audit? If companies are following the standard to provide annual training, then the assessments for each task would at times be duplication of the annual and on going training and therefore create additional work for a trainer. The OTS supports assessing the capabilities of the operators, however, we suggest it be more in line with the system operator certification, i.e. every three years.
Response:			

4. Do you agree with the Time Horizon for each requirement in the revised standard? If not, please explain in the comment area.

Summary Consideration:

Question #4			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		No comment.
Florida Power & Light	☑		No comment.
FRCC	☑		No comment.
LCRA		☑	If I do not agree with the requirments in the first place, then I can hardly agree with any time line.
Response:			
NYISO	☑		No comment.
OVEC	☑		No comment.
PHI	☑		No comment.
SMUD	☑		Please define Long Term Planning.
Response:			
APS		☑	Since an approved training program based on SAT may not be ready for 36 months per 5.3, the assessment of training mismatch cannot be done until then. So, Requirement 2 should also become effective 36 months after the standard's approval.
Response:			
Santee Cooper	☑		No comment.
Avista	☑		No comment.
Entergy (1)	☑		Please add Time Horizon values to R1.1, R2.1, R2.2 and R3.1 and R3.1.1. It is not obvious the Time Horizon assigned to the Requirement also applies to the sub-requirement.
Response:			
FirstEnergy	☑		
Quality Training Systems			No comment.
Response:			

Question #4			
Commenter	**Yes**	**No**	**Comment**
TAL	☑		Each requirement has a "Long-term Planning" horizon.
Response:			
Madison G&E		☑	a) Entities have established training programs per Regulatory Approved Standards. Proposed Effective Date, 5.1 is the only parallel, carry over requirement from a Regulatory Approved Standard (PER-002-0, R4) to this proposed standard. This time frame is workable. b) Proposed Effective Date, 5.2 is unclear (see comments of 2.a, above), so an effective date cannot be proposed yet. c) Proposed Effective Date, 5.3 for the proposed SAR contains over 370 tasks for operators and the time line is too aggressive. Registered Entities will need to be trained in the Systematic Approach to Training process, set up their own processes, convert established training to the SAT process, create new training and start to give training to System Operators. Budgets will need to be forecasted, personnel will need to be tasked with the training process (most companies have a small training department), this will take an extreme amount of time and cost are unknown at this time.
Response:			
Entergy (2)	☑		
ERCOT		☑	See comments on #9.
Response:			
Southern	☑		Long-term planning is the appropriate time horizon.
Response:			
Allegheny Power			
AEP	☑		
ATC	☑		
BCTC	☑		The requirement time horizon as Long Term Planning is okay.
CAISO		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. The CCC will have final say on these elements in any case; therefore the SDT would save itself some effort by focusing on the primary elements before weighing in on the compliance elements.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			However, given the question being posed: The CAISO believes that assigning long-term planning to all the requirements is inappropriate, if not over-simplistic. For example, the annual assessment of the training need and the subsequent development-of/revision-to a training program, as the requirement implies, occurs once every 12 months. This is normally regarded as an operations planning time frame if violation of this requirement is to be mitigated. Training in each of the requirements can cross over time horizons. Requirement 1 (which has not been vetted) states the entity must use the SAT 5 phases for all reliability-related tasks. If a new task that requires training is created for implementation tomorrow, how would that training program fall under long-term planning? Requirement 4 - when a new task arises, (assuming one accepts the premise of the requirement itself) then shouldn't the assessment take place as soon as possible?
Response:			
CenterPoint	☑		
NIPSCO		☑	The annual assessment is scheduled to begin before the baseline criteria for the evaluation is developed. It would be more beneficial to develop the standards upon which the evaluation will be based first so that the operators know what is expected from them.
Response:			
NPCC RCS	☑		
PG&E (1)			
PG&E (2)	☑		However, we would like a definition for long term planning?
Response:			
PJM		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. The CCC will have final say on these elements in any case; therefore the SDT would save itself some effort by focusing on the primary elements before weighing in on the compliance elements. However, given the question being posed:

Question #4			
Commenter	Yes	No	Comment
			PJM believes that assigning long-term planning to all the requirements is inappropriate, if not over-simplistic. For example, the annual assessment of the training need and the subsequent development-of/revision-to a training program, as the requirement implies, occurs once every 12 months. This is normally regarded as an operations planning time frame if violation of this requirement is to be mitigated. Training in each of the requirements can cross over time horizons. Requirement 1 (which has not been vetted) states the entity must use the SAT 5 phases for all reliability-related tasks. If a new task that requires training is created for implementation tomorrow, how would that training program fall under long-term planning? Requirement 4 - when a new task arises, (assuming one accepts the premise of the requirement itself) then shouldn't the assessment take place as soon as possible?
Response:			
SRP	☑		
SDG&E		☑	It is unclear what is the meaing of the time horizons.
Response:			
We Energies	☑		
Garland		☑	Do not agree with the annual time line in R2. Long Term planning should be defined.
Response:			
HQT	☑		
IESO	☑	☑	We do not agree with some of the requirements in the standard (see our comments under Q11) hence we have difficulties commenting on the time horizons. Given what's written, however, our general comment is that assigning long-term planning to all the requirements is inappropriate, if not over-simplistic. For example, the annual assessment of the training need and development of/revision to a training program, as the requirement implies, occurs once every 12 months. This is normally regarded as an operations planning time frame if violation of this requirement is to be mitigated.
Response:			
ISO New England	☑		
Manitoba Hydro		☑	Do not understand what this means.

Question #4			
Commenter	**Yes**	**No**	**Comment**
Response:			
MISO Stakeholders		☑	As a general rule, we do not agree to any assignments of time horizons because time horizons were never vetted through the industry. The definitions also are not posted on the NERC web site in a prominent location. There were no time horizons assigned for R1 and R2 in PER-004-2.
Response:			
MRO	☑		
SPP ORWG	☑		It is our understanding that the Time Horizon of Long-term Planning allows a mitigation period of one year or more.
Response:			
WECC OTS	☑		However, we would like a definition for long term planning?
Response:			

5. Do you agree with the Violation Risk Factor for each requirement in the revised standard? If not, please explain in the comment area.

Summary Consideration:

Question #5			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	While qualified trained operators are important and thus traiining might appear to imply a greater VRF, the mechanics of training should be considered LOWER.
Response:			
Florida Power & Light		☑	The risk factors associated with the training standards should be "Lower" risk factors. These training activities will be occurring outside of the "real-time" operating arena and therefore violations of these requirements cannot in and of themselves cause impacts as defined by "Medium" risk factors. An entity would be required to violate several core operating requirements prior to the violation of a training requirement having any material impact on a system. At that, the linkage of an event to a training activity would be extremely subjective.
Response:			
FRCC		☑	The risk factors associated with the training standards should be "Lower" risk factors. These training activities will be occurring outside of the "real-time" operating arena and therefore violations of these requirements cannot in and of themselves cause impacts as defined by "Medium" risk factors. An entity would be required to violate several core operating requirements prior to the violation of a training requirement having any material impact on a system. At that, the linkage of an event to a training activity would be extremely subjective.
Response:			
LCRA		☑	See #4.
Response:			
NYISO		☑	Medium is an excessively high risk factor.
Response:			
OVEC		☑	The Risk Factor for each requirement should be low. Each of the requirements appear to be more administrative in nature and do not warrant a Medium risk factor as is currently assigned.
Response:			
PHI	☑		

Question #5			
Commenter	**Yes**	**No**	**Comment**
SMUD		☑	All entities' risk factors should be assessed based on their possible impact to the BES.
Response:			
APS			No comment.
Santee Cooper	☑		No comment.
Response:			
Avista		☑	For instance R2.3.1 is a Violation Risk Factor of High. SAT is not necessary; adaquate training programs exist currently without the benefit of SAT; therefore, a Violation Risk Factor of Low is more reasonable.
Response:			
Entergy (1)	☑		Please add VRFs to R1.1, R2.1, R2.2 and R3.1 and R3.1.1. It is not obvious the VRFs assigned to the Requirement also applies to the sub-requirement.
Response:			
FirstEnergy	☑		
Quality Training Systems			No comment.
TAL		☑	These are not real time requirements. Any potential impact to the BES will be adequately captured in other approved standards and violation severities. These should all be Lower!
Response:			
Madison G&E		☑	Since Violation Severity Levels have not been vetted through the electrical industry, levels of severity can not be applied to the proposed standard.
Response:			
Entergy (2)		☑	We believe these items to be in the LOWER risk factor category.
Response:			
ERCOT		☑	This has not been properly vetted through the industry. Furthermore, this is an administrative standard and medium to high risk should not apply unless the training program is grossly inadequate.
Response:			
Southern	☑		Medium risk factor is appropriate for all.
Response:			
Allegheny Power			
AEP		☑	R1. - No. This should be a "low" risk factor". An entity could do very good training without using the SAT, still identify reliability tasks, and not be at risk. Not providing a

Question #5			
Commenter	**Yes**	**No**	**Comment**
			training program or avenue of training could be a "medium" risk factor, but not using SAT (ADDIE) is a "low" risk factor. SAT (ADDIE) is a great guide, but it doesn't warrant being a part of the standard requirement. The true requirement of R1 should be the requirement of entities to have a training program with training objectives to support the identified reliability tasks. If the only requirement of R1 was the requirement to identify Reliability Tasks (R1.1), a "Medium" risk factor might be appropriate. Renumbering of R1.1 and making it R2, thus separating this requirement from the SAT requirement, would be an improvement, and would allow two different risk factors. (Also see comments of Question 6 and Question 11 for R1) R2. - Yes. "Medium" risk is OK. R3. - Yes. "Medium" risk factor is OK. R4. - Yes. "Medium" risk is OK.
Response:			
ATC	☑		
BCTC		☑	These requirements changes are generally administrative issues and should be risk factor Low.
Response:			
CAISO		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. The CCC and FERC will have final say on these VRFs, therefore the SDT would save itself some effort by focusing on the primary elements before weighing in on the compliance elements.
Response:			
CenterPoint			
NIPSCO	☑		
NPCC RCS	☑		
PG&E (1)			
PG&E (2)		☑	The purpose of the Violation Risk Factors is for use when determining a penalty or

Question #5			
Commenter	**Yes**	**No**	**Comment**
			sanction. In reviewing the measures all requirements are administrative in terms of providing documentation that the requirement has been met. Training generally occurs outside of the real-time operations which have little impact on the BES and therefore a "Lower" risk factor versus the "Medium/High" risk factors would be appropriate.
Response:			
PJM		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. The CCC and FERC will have final say on these VRFs, therefore the SDT would save itself some effort by focusing on the primary elements before weighing in on the compliance elements.
Response:			
SRP	☑		
SDG&E			
We Energies	☑		
Garland		☑	I think the Violation risk factor for training requirements should be lower than a medium.
Response:			
HQT	☑		
IESO	☑		Given what's written, but we do not agree with some of the requirements (see Q11, below).
Response:			
ISO New England	☑		
Manitoba Hydro	☑	☑	It is hard to believe that we are still mixing risk with importance. Yes training is an important component but it is a stretch to say that missing some item or document is going to place the system at risk.
Response:			
MISO Stakeholders		☑	As a general rule, we do not agree with the assignment of any Violation Risk Factors to any requirements since the Violation Risk Factor definitions have not been vetted through the industry. One could make a case that the lack of a training program could be a medium risk violation, however there should be no medium or high risk requirements in an administrative standard. We appear to be confusing importance with the probability of cascading.
Response:			
MRO	☑	☑	There is varied opinion on this. Perhaps the majority opinion is: It is hard to believe that we are still mixing risk with importance. Yes training is an important component but it is

Question #5			
Commenter	**Yes**	**No**	**Comment**
			a stretch to say that missing some item or document is going to place the system at immediate risk. MRO suggest these be assigned as LOW but does agree that training is important. Others agree with assigning Medium.
Response:			
SPP ORWG		☑	We can concur with maintaining the VSL of Medium on Requirement 1 but would recommend dropping the VSL to Low for R2, R3 and R4 since these requirements tend to be administrative.
Response:			
WECC OTS		☑	OTS recommends the violation risk factors be set to 'Lower'. The purpose of the Violation Risk Factors is for use when determining a penalty or sanction. In reviewing the measures all requirements are administrative in terms of providing documentation that the requirement has been met. Training generally occurs outside of the real-time operations which have little impact on the BES and therefore a "Lower" risk factor versus the "Medium/High" risk factors would be appropriate.
Response:			

6. Do you agree with the Measures identified for each requirement in the revised standard? If not, please explain in the comment area.

Summary Consideration:

Question #6			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	The required documentation needed for these measures is not well defined. Is a journal sufficient?, or a certificate?
Response:			
Florida Power & Light		☑	M 1.4 - What would be required documentation for training delivered by an outside vendor? Would certificates be sufficient? M-2 - see comment on number 1 above. M-4 - see comment on number 3 above.
Response:			
FRCC	☑	☑	M 1.4 - What would be required documentation for training delivered by an outside vendor? Would certificates be sufficient? M-2 - see comment on number 1 above. M-4 - see comment on number 3 above.
Response:			
LCRA		☑	Again, it is an unreal expectation to believe that smaller utlities can manage what amounts to an entirley new massive program.
Response:			
NYISO		☑	M4 is unmeasureable. Replace the wording "verification of the capabilities" with "training records". R4 is not measurable. Please replace the following: Each Reliability Coordinator, Balancing Authority and Transmission Operator shall maintain training records of each of its real-time System Operators. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall maintain records of training programs provided to address the tasks on its list of company-specific BES reliability-related tasks.
Response:			
OVEC		☑	The M1 sub-measures are written more like requirements than measures. The submeasures should be deleted. Revise M1 to read, "Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evdience of a SAT developed BES System Operator training program as stated in R1." This wording clearly measures all that is stated in requirement R1.

Question #6			
Commenter	**Yes**	**No**	**Comment**
			In M2 it is unclear why the word "position" was included. For M3, delete the words "or system restoration training." Sytem restoration is considered a part of emergency operations.
Response:			
PHI	☑		Except where we would like some clarification of Requirement 2 so that we would be clear about what is being assessed. See our comment to Q1.
Response:			
SMUD	☑		
APS		☑	M1.4. The "E" in ADDIE means evaluations and assessments of training effectiveness. It does not directly refer to student evaluation, of whether "learning objectives are met" (i.e. exams, which are administered during Implementation). "E"valuation more often refers to Feedback, Exam Performance, Post-Training Evaluation, and Return on Investment studies. M4. (See Item 3 above) This "Measure" can never be consistently applied. Regarding this requirement, the Background Information on Page 3 of this document says "the standard does not specify how entities will measure this capability", leaving nothing but a future of debates during Audit Week.
Response:			
Santee Cooper		☑	M2, M3, and M4 appear to be appropriate measures. M1 and R1 should not be included in a Reliability Standard. The Standard should address training that is required and not dictate how a company should implement their training.
Response:			
Avista		☑	M1- Removal of the term "job task analysis" but still requiring one is not much of a change from the previous draft. Again requiring every entity to have a SAT based training program is unnecessary.
Response:			
Entergy (1)		☑	As written, M1 is intended to measure the "process" used to derive the result of each step of the SAT. We disagree with that measure. We suggest the Measure for R1 be a review of the "results" of each step of the SAT, not measure the process for development of those results. Given the specific wording of these requirements and measures, we are not sure what is

Question #6			
Commenter	**Yes**	**No**	**Comment**
			being measured in M2. What is being measured in M2? Please be more specific in the words. For instance, is the "latest assessment for each position" and assessment of the job category, or an assessment of the individual employees performing in that position? Please make this measure significantly more clear and specific. M3 should be deleted and moved to EOP-005. We have similar issues with M4 as for M2, and a similar interpretation of the issues identified above for M2. What constitutes verification of the capabilities? Is this verification of a person's performance appraisal? Is this a verification of the basic training requirements of a person to fill a position, like having a BSEE from an accredited university? Please make this measure significantly more clear and specific.
Response:			
FirstEnergy	☑		Many of the measures provide no additional information beyond the information contained in the requirement except to say "provide the evidence". In addition, where they do provide additional information, the measurement value is not contained in the requirement. As an example, measure M1.1. states that, "Analysis that results in a list of company-specific BES reliability-related tasks and measurable or observable criteria for desired performance for each task." However, there is nothing in R1 or the sub-requirements that states measurable or observable criteria for desired performance must be developed. All requirements should be clearly stated in the requirements section of the standard and the measures section should not impose new or additional requirements.
Response:			
Quality Training Systems			No comment.
TAL		☑	M1. This measure has no allowance for the use of outside vendors in a training plan. If a NERC Certified Provider is utilized, the entity should not be required to retain the providers documentation as required in M1.2 and M1.4. the retention of "evaluations and assessments" may include the use of end-of-course examinations which would violate exam security for the vendor if the entity has to retain them. The fact that CEH's were awarded should be sufficient for M1.2 and M1.4 in the case where a CEH provider (even if it was the parent entity) is utilized. The industry has spent a lot of time, money and effort into getting the CEH program up and running. It has become the only way to maintain NERC Certification. Lets use it to

Question #6			
Commenter	**Yes**	**No**	**Comment**
			it's fullest potential. If it is good enough for Credential maintenance, it should be good enough for the training program compliance. Violators of the CEH provider rules already have a method to be scrutinized. M2. This relates to Question 1. Is the intent to retain documentation for the Operator position or the Operator that mans the position and sits at the desk?
Response:			
Madison G&E		☑	M1.2, Unclear what the difference is between "design" and "development", and these are in fact lumped into one measure even though they are considered 2 separate steps for the SAT process.
Response:			
Entergy (2)		☑	M1, as currently written, is a review of an entity's entire training program from inception. This may be too broad of a Measure.
Response:			
ERCOT		☑	Should state "applicable SAT-related outcomes" rather than "SAT related outcomes". The current wording will create unnecessary work. For example, an Analysis may show that the simplicity and frequency of a task does not need to move beyond the Analysis phase. This can be an audit liability when taken literally. M.4 Should state "Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection verification of the qualifications for each real-time System Operator and their assigned positions, as specified in R4."
Response:			
Southern	☑		
Allegheny Power			
AEP		☑	M1 - This measurement should require evidence of a training program that supports training and identification of reliability tasks, but the approach to training should be the choice of the operating entity. (R1 - SAT should be a guide given as a reference document, but should not be a requirement and measurement of the standard; see additional comment in Question 11). M2 - OK M3 - OK

Question #6			
Commenter	**Yes**	**No**	**Comment**
			M4 - OK.
Response:			
ATC	☑		
BCTC		☑	From the comments we have provided we are suggesting the changes to the requirements are overall not acceptable, therefore the measures would have to be changed to reflect the changes to the requirements that are acceptable.
Response:			
CAISO		☑	Measure 1 is not quantifiable. What evidence will demonstrate 'desired performance', if the desired performance is not defined in the standard itself? Because Requirement 2 is subjective, Measurement 2 is meaningless in the context of a NERC reliability standard. Measurement 3 is proof of attendance and not a true indicator of reliability impacts. Measurement 4 requires that the subjective verification of the "capabilities" be documented. Even if such a measurement could be standardized, as written, this measurement requires nothing more that documentation of ineptness.
Response:			
CenterPoint			
NIPSCO	☑		
NPCC RCS		☑	It must be clear that no personal information or assessments that may be confidential are part of M2. The information should strictly be related to the System Operator's skills. Also see number 8 below regarding R1 and M1.
Response:			
PG&E (1)			
PG&E (2)		☑	If the requirements change, then the measures should be changed to reflect the revised requirement.
Response:			
PJM		☑	Measure 1 is not quantifiable. What evidence will demonstrate 'desired performance', if the desired performance is not defined in the standard itself? Because Requirement 2 is subjective, Measurement 2 is meaningless in the context of a NERC reliability standard.

Question #6			
Commenter	**Yes**	**No**	**Comment**
			Measurement 3 is proof of attendance and not a true indicator of reliability impacts. Measurement 4 requires that the subjective verification of the "capabilities" be documented. Even if such a measurement could be standardized, as written this measurement requires nothing more that documentation of ineptness.
Response:			
SRP	☑		
SDG&E			
We Energies		☑	Wording of M1 and sub measures should be simplified/clarified. Wording of M1.2 should not preclude using training material from a vendor.
Response:			
Garland		☑	Again, small utilities can not manage a large training program with unreal expectations for training requirements. This would be great if you had unlimited resources or was only in the training business and not having to manage real time operations at the same time on a daily basis.
Response:			
HQT		☑	It must be clear that no personal information or assessments that may be confidential are part of M2. The information should strictly be related to the System Operator's skills. Also see Q8 below regarding R1 and M1.
Response:			
IESO	☑	☑	Yes, given what's written, but we do not agree with some of the requirements (see Q11, below). In addition, we think M3 should be expanded to cover the sub-requirements in R3. One item of particular concern is an entity is assigned a Low violation if it is found that it did not add or remove topics from the Emergency Operations Topics. This is not covered in M3, which only covers the 32 hour training duration requirement.
Response:			
ISO New England		☑	It must be clear that no personal information or assessments that may be confidential are part of M2. The information should strictly be related to the System Operator's skills. Also see number 8 below regarding R1 and M1.
Response:			
Manitoba Hydro		☑	On quick review it looks like additional requirements are being placed in the measures. The measures are complex and may not be understood.
Response:			

Question #6			
Commenter	**Yes**	**No**	**Comment**
MISO Stakeholders		☑	Measure 1 is confusing due to the sub-measures. Is this trying to say the training program shall have these four critieria? If so, it needs to be worded better. For example, we suggest simply replacing M1.1 with: A list of company specific BES reliability-related tasks with measurable criteria for each task. This is much simply and clearer.
Response:			
MRO		☑	On quick review it looks like additonal requirements are being placed in the measures. For example, M1.1, seems to add an additional requirement of having measurable or observable criteria for desired performance for each task which is not stated in R1. The measures are complex and may not be understood. For example, in M4, it is not clear how "varification of the capabilities for each real-time operator" can actually be achieved and then varified to an auditor. In may also be inpractical to varify capability to perform some tasks if the individual operator has never actually been in a situation to demonstrate capability - follow the correct procedures to initiate loadshed in an emergency, for example.
Response:			
SPP ORWG	☑		Although we can not offer any suggestions for making it more focused, Measurement 1 is very broad. We are concerned about how we would be able to demonstrate that we have satisfied the requirements the way it is currently written.
Response:			
WECC OTS		☑	OTS is suggesting in its comments changes to the requirements, therefore the measures would be changed to reflect the changes to these requirements. It also does not address training provided by third parties or vendors. What requirements would companies be under if this type of training were provided?
Response:			

7. Do you agree with the Compliance Monitoring Process section (D1) in the revised standard? If not, please explain in the comment area.

Summary Consideration:

Question #7			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	Once again the time period is not well defined.
Response:			
Florida Power & Light		☑	D1.2 - What is the compliance Monitoring Period? Should the Reset period be one month when these are apparently annual requirements? D1.3 - Why is data retention four years? What is the benefit of an additional year of records past the last compliance audit which is required every 3 years per D1.4? - Is the retention of "any data used in mitigation plans associated with this standard" intended to be an indefenite retention? This is not clear. Is the "mitigation plan" intended to be mitigation for the entity to get in compliance with the standard, or for the individual operator to achieve the desired performance level per the entity's training plan?
Response:			
FRCC		☑	D1.2 - What is the compliance Monitoring Period? Should the Reset period be one month when these are apparently annual requirements? D1.3 - Why is data retention four years? What is the benefit of an additional year of records past the last compliance audit which is required every 3 years per D1.4? - Is the retention of "any data used in mitigation plans associated with this standard" intended to be an indefenite retention? This is not clear. Is the "mitigation plan" intended to be mitigation for the entity to get in compliance with the standard, or for the individual operator to achieve the desired performance level per the entity's training plan?
Response:			
LCRA		☑	See #4.
Response:			
NYISO		☑	There is no requirement that requires data retention. There should be. See the proposed rewording of R4 above.

Question #7			
Commenter	**Yes**	**No**	**Comment**
			Mitigation plans are addressed nowhere in the standard except in data retention. It is an undefined term.
Response:			
OVEC		☑	In Section D, 1.4 the annual self-certification submittal should not be included in the standard but left to NERC's discretion to either include or exclude monitoring in the annual compliance and enforcement program. The impact on the system from this standard is minimal if it is not monitored for compliance on a yearly basis.
Response:			
PHI	☑		
SMUD	☑		Please define Compliance - 1.2 Monitoring Period Reset.
Response:			
APS			No comment.
Santee Cooper		☑	Most NERC Standards require three years or less for documentation to be maintained.
Response:			
Avista		☑	
Entergy (1)	☑		
FirstEnergy		☑	The compliance monitoring and reset period is a vague concept that may be of little or no value in the mandatory compliance regime. Under the mandatory compliance regime, non-compliance is followed by a mitigation plan that contains the date by which compliance will be achieved and thus reset the compliance clock. This reduces or eliminates the value of the monitoring and reset period.
Response:			
Quality Training Systems			No comment.
TAL		☑	D1.2 - What is the compliance Monitoring Period? Should the Reset period be one month when these are apparently annual requirements? D1.3 - Why is data retention four years? What is the benefit of an additional year of records past the last compliance audit which is required every 3 years per D1.4? - Is the retention of "any data used in mitigation plans associarted with this standard" intended to be an indefenite retention? This is not clear. Is the "mitigation plan" intended to be mitigation for the entity to get in compliance with the standard, or for the individual operator to achieve the desired performance level per the entity's training

Question #7			
Commenter	**Yes**	**No**	**Comment**
			plan?
Response:			
Madison G&E		☑	a) It is unclear what the one month period is meant to be in Compliance 1.2. If it is meant to mean that the requirements need to be met monthly, then the requirements are too in-depth to be met on a monthly basis. A full evaluation of each operator on a monthly basis in particular would be impractical. R3 already mentions it is an annual requirement, and this time period seems reasonable for all of the requirements. b) Data Retention, 1.3, Do not understand the 4 year retention period, since Registered Entities (RC, TO, BA) will be audited every three years.
Response:			
Entergy (2)	☑		
ERCOT		☑	The requirments for self-certification should be identified. Without reasonable guidelines, a Regional Entity will have free reign to set whatever self-reporting standards it deems fit. With the current wording, annual self-certification has the potential to become very stringent.
Response:			
Southern		☑	Under D2.2 and D2.3.1.1 it states in the Note for each of the subsections that if R1.1 or R1.2 is violated, the entity is also in violation of R1. This is double jeopardy and does not seem correct, especially where the subsection only provides more detail about what is being required in the above section and does not represent a new requirement. R1 says you must complete the five phases of a SAT to establish a new or modify an existing company specific training program. R1.1 provides some specific details about what the analysis phase of the SAT training program should consist of. If you do not complete R1.1 adequately then there should be only one violation and not two violations. Under Data Retention, a minimum of four years of data retention is not appropriate. It should be restated to say a maximum of 3 years of data should be retained or since the last compliance audit has been performed. However, if the entity had been found to be non-compliant for a particular requirement in the most recent compliance audit, then additional data should be retained for longer than the previous compliance audit but no longer than 3 years.

Question #7			
Commenter	**Yes**	**No**	**Comment**
Response:			
Allegheny Power			
AEP		☑	D1.3. - We do not see the benefit of increasing the data retention from 3 years to 4 years. NERC Readiness evaluations and Regional Compliance audits are based on 3 years. PER-002-0 present data retention compliance is 3 years. Holding data since last audit (3 years) should be adequate.
Response:			
ATC	☑		
BCTC	☑		1.2. We are not clear what a performance reset period is but we are okay with it; 1.3 and 1.4 okay.
Response:			
CAISO		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. We note the following: 1. The entity "Compliance Enforcement Authority" is a new term. It is not found in the Functional Model. 2. The compliance elements should not impose requirements that are not in the standard itself. To require a responsible entity to maintain records on whether it is following or followed any mitigation plan associated with the standard is outside the standard itself. The standard does not address mitigation plans anywhere. This also applies to the requirement on the Compliance Monitor to retain any data used in mitigation plans associated with this standard, particularly since the Compliance Monitor does not appear on the Applicability List at the beginning of the standard.
Response:			
CenterPoint			
NIPSCO		☑	Compliance monitoring period and reset lists the performance reset period for all requirements at one month, which would make the annual training requirements ineffective.
Response:			
NPCC RCS		☑	D1.2, the reset period seems unrealistic and short. The assessment is due annually. D1.3 delete onsite. Also who is the Compliance Monitor intended to be.
Response:			

Question #7			
Commenter	**Yes**	**No**	**Comment**
PG&E (1)			
PG&E (2)		☑	D.1.2 What is the compliance monitoring period and when does the reset period begin if training is an annual requirement? D.1.3 is referencing data retention; a question arises over "mitigation plans". Who does it apply to, the entities program or the operator? We also question the four year data retention, what is the purpose since it is counter to D.1.4 requirement of a Compliance Audit every three years.
Response:			
PJM		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. PJM would note the following: 1. The entity "Compliance Enforcement Authority" is a new term. It is not found in the Functional Model. 2. The compliance elements should not impose requirements that are not in the standard itself. To require a responsible entity to maintain records on whether it is following or followed any mitigation plan associated with the standard is outside the standard itself. The standard does not address mitigation plans anywhere. This also applies to the requirement on the Compliance Monitor to retain any data used in mitigation plans associated with this standard, particularly since the Compliance Monitor does not appear on the Applicability List at the beginning of the standard.
Response:			
SRP	☑		
SDG&E			
We Energies	☑		1.3 Data Retention - how long must evidence that a mitigation plan was followed be kept?
Response:			
Garland		☑	I do not agree with the requirements in the standard, so the Compliance Process can not be addressed until the requirements are agreed upon.
Response:			
HQT		☑	D1.2, the reset period seems unrealistic and short. The assessment is due annually. D1.3 delete onsite. Also who is the Compliance Monitor intended to be.

Question #7			
Commenter	**Yes**	**No**	**Comment**
Response:			
IESO		☑	We have difficulties with the following elements: 1. The entity "Compliance Enforcement Authority" is a new term and should be replaced with the equivalent Functional Model entity. 2. The compliance elements should deal with assessing whether or not, or the extent to which, responsible entities meet the requirements according to the measures. To require a responsible entity to maintain records on whether it is following or followed any mitigation plan associated with the standard appears to be a follow-up process after the entity has been assessed non-compliant. This seems to be outside the scope of a standard. Similar comment on the requirement for the Compliance Monitor to retain any data used in mitigation plans associated with this standard, and the Compliance Monitor is not on the applicability list.
Response:			
ISO New England		☑	D1.2, the reset period seems unrealistic and short. The assessment is due annually. D1.3 delete "onsite." Also who is the Compliance Monitor intended to be.
Response:			
Manitoba Hydro		☑	The Violation Security Levels are too complex to follow.
Response:			
MISO Stakeholders		☑	We have the following issues and concerns: 1. Doesn't the Compliance Monitoring Period and Reset of one-month make the annual training requirement ineffective? Since it is reset every month, can you ever really measure if 32 hours have provided? It seems that it should not be reset each month. 2. What is the justification for retaining documentation more than 3 years. Three years is generally the longest a standard requires for data retention unless there is a violation. There should be strong justification for this. We can't fathom what it is. 3. Section 1.4 should be completely removed. It is written in a way that would require the regional entity to include this standard in their annual Compliance Monitoring and Enforcement Program every year and dictates to the region how compliance will be monitored. Isn't this up to the region? It also duplicates the requirement for a

Question #7			
Commenter	**Yes**	**No**	**Comment**
			compliance audit every three years. It does not need to be repeated here.
Response:			
MRO			The term Compliance Enforcement Authority (CEA) needs to be defined as it seems this is a previously undefined entity. Why not just say Regional Entity?
Response:			
SPP ORWG		☑	There is an inconsistency between the data retention requirement in D1.3 and the on-site review requirement in D1.4. We would suggest deleting the phrases '…for four years, or…' and '…, whichever is greater.' in the first sentence of D1.3. Both time period requirements would then be based on the last on-site audit.
Response:			
WECC OTS		☑	OTS does not agree with the Compliance Monitoring Process in the revised standard and has several questions. D.1.2 What is the compliance monitoring period and when does the reset period begin if training is an annual requirement? D.1.3 is referencing data retention; a question arises over "mitigation plans". Who does it apply to, the entities program or the operator? We also question the four year data retention, what is the purpose since it is counter to D.1.4 requirement of a Compliance Audit every three years.
Response:			

8. Do you agree with the Violation Severity Levels for each requirement in the revised standard? If not, please explain in the comment area.

Summary Consideration:

Question #8			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	Training should not be Severe or HIgh, those should be reserved for direct links to reliability.
Response:			
Florida Power & Light		☑	I do not feel that any VSL should be severe or high in relation to a training program.
Response:			
FRCC		☑	FRCC does not feel that any VSL should be severe or high in relation to a training program. D2.4.3 - Grammatically incorect. Second paragraph should end " training has not BEEN provided annually."
Response:			
LCRA		☑	See #4.
Response:			
NYISO		☑	The risk factor should be LOW for R2. There is no risk to reliability if the mismatch does not result in reliability impacts in real-time operation. Real time reliability standards are addressed in other documents. If there are tasks that fall below expectations that do not effect system reliability as measured by NERC standards, then their impact on reliability is low.
Response:			
OVEC		☑	Generally, the whole violation severity level section is far too cumbersome and verbose to understand and implement. Specifically, for Section 2.1.3 what if the entity did not find it necessary to add or remove any topics from the list? Why is that a violation? The section seems to indicate that the list has to have items constantly removed or added to have no violation occur. For section 2.2.2 what is meant by the addition of the word "capability?" For section 2.2.3, if the 32 hours of training is not included in Attachment B then either Attachment B needs revised or deleted or the continuing education hours program also used to identify emergency operations courses needs revised. Suggest remove 2.2.3 entirely or remove the words, "or sytem restoration", and "but did not include training in subject areas listed in Attachment B." Section 2.3, the bulleted items seem to read as requirements rather than as measures. Section 2.3.2.1, again, what is

Question #8			
Commenter	Yes	No	Comment
			meant by the addtion of the word "capability?" Section 2.3.3.1, this section reads as a requirement rather than as a measure.
Response:			
PHI		☑	PHI feels the wording of the Violation Severity Levels is confusing. Lower does not seem reasonable - If an entity has reviewed the list, agrees with it completely and has nothing to add, they would appear to be in violation. Similarly Moderate seems to be saying that if an entity has started creating a list of all reliability related tasks but hasn't finished it, has identified training but hasn't scheduled it or has given so called EOP training but not from topics on Attachment B and done nothing else--they warrant a Moderate violation. But, if they have done almost everything but not quite met the requirement, they warrant a High violation. We are sure this is not the way these are meant to be understood. Perhaps starting with the Severe Violations and working down to moderate would be a better way to delineate what a moderate and lower violation would look like.
Response:			
SMUD	☑		2.2.2 What tasks should be reviewed? Every task associated with each operating position or BES company specific reliability issues? 2.2.3 Regarding attachment “B” – Does this require all tasks listed or only selected topics? 2.3.2 Should this be limited to BES company specific reliability tasks. 2.1.3 Should read "The responsible entity did not add or remove topics from the Emergency Operations Topics as provided in attachment “B” that apply to their organization." Severity levels may be too excessive.
Response:			
APS		☑	Based on your definitions, the problem descriptions written for each of the four severity levels will ALL constitute "Severe" violations. For example, Item 2.1.3 lists topics from the EO list that were not added/removed when applicable, which constitutes a failure of the Analysis process and a failure of the Evaluation process too, because you didn't detect the problem and fix it. Since two phases of SAT were not done, this condition automatically meets the definition of 2.4 as "Severe". The same with item 2.2.1 and 2.3.1.

Question #8			
Commenter	**Yes**	**No**	**Comment**
			This area needs work.
Response:			
Santee Cooper		☑	The standard should not dictate how a training program should be implemented as implied by 2.3.1. Severe Level for the 32 hours of EOPs would be that no training was provided to any of the operators, High would be that some training was provided but not all 32 hours or several operators did not complete all 32 hours. Moderate would be that 32 hours were provided but one operator did not complete or the training did not include drills, exercises, or simulations. If one operator does not complete 32 hours of EOPs training as written in 2.3.3, it should be a Moderate Violation Severity Level rather than a High Violation Severity Level. The violation severity levels associated with the other requirements aren't appropriately graduated either.
Response:			
Avista		☑	Disagree based on SAT requirement.
Response:			
Entergy (1)		☑	VSL 2.2.1 contains the statement that if the entity violates R1.1, the entity is also in violation of R1. We believe this is being penalized twice for the same infraction and should be deleted. Item 2.2.3 states "but did not include training in the subject areas listed in Attachment B". The Requirement R3.1 is that Attachment B is modified by the BA, TOP or RC. Therefore, this VSL should be changed to "... listed in R3.1.1". Due to the formating of the VSL documentation it is difficult to be sure what are the intended VSLs of section 2.3.1, 2.3.2, 2.3.3, and 2.4.1.1. For instance, VSL is High in 2.3.2 for not performing an assessment. Is the VSL also High for section 2.3.2.1 which states the "entity has not identified training required"? Or, is 2.3.2.1 instead of 2.3.2? Again, the Severe VSL identified for 2.4.1 has three parts identified as "OR". However, there is an additional reference 2.4.1.1 which is part of 2.4.1. Should there be an "AND", or an "OR" infront of 2.4.1.1?

Question #8			
Commenter	**Yes**	**No**	**Comment**
			We suggest VSLs for the 32 hour training in R3, and the VSLs for R4 are OK. We also suggest the VSL criteria be redistributed for each of the Requirements R1 and R2. We think 2.4.2, R2, an entity who has "not performed an assessment which includes … to each task …" should have a much lower VSL applied to it than an entity that does " not have a SAT program" at all. Both of these criteria are considered Severe in the draft standard. Starting with Severe, we agree Severe should be assigned to having NO SAT program, 2.4.1 for R1, and the criteria that the entity has not performed an assessment of operator capabilities, 2.4.4 for R4. These are the only two actions that rise to the level of Severe. We suggest all the criteria for R1 and R2 be moved down one level, from Severe to High, from High to Moderate, and Moderate to Lower, except the criteria as noted above.
Response:			
FirstEnergy		☑	The process for establishing VSLs is presently being vetted through the industry for the 83 FERC approved standards. We believe it is prudent to let that process take its course so that SDTs presently working on revised or new standards can reference the new format in establishing VSLs. The violation severity levels as written are interlaced making it difficult to determine the violation severity level that pertains to each requirement. The violation severity levels should be listed by requirement. In addition the following revisions to the wording are suggested: Item 2.2.2 should be revised to state, "The responsible entity has determined training required based on the mis-match between acceptable and actual performance capability but has not included this training in its current schedule." Item 2.2.3 should be revised to state, "The responsible entity annually provided at least 32 hours of training on emergency operations or system restoration but the training did not include the subject areas listed in Attachment B." Item 2.3.3 should be revised to state, "The responsible entity provided to its system

Question #8			
Commenter	**Yes**	**No**	**Comment**
			operators at least, 32 hours of emergency operations or system restoration training, annually, but not all its System Operators have completed or evidence shows all of its System Operators will not have completed the required annual training." Item 2.4.1 should be revised from, "The responsible entity does not have a SAT program for its system operators" to "The responsible entity has not used the SAT process to develop its training program." Item 2.4.2 states, "The responsible entity has not performed an assessment which includes identification of measurable or observable criteria for desired performance to each task for the determination of the training needs for two of its system operating position." Looking past the fact that there is no requirement to identify measurable and observable criteria for desired performance, the severity level as written appears to state that I cannot get a severe violation severity raking if I only have one operator position. This should be revised to state, "… training needs for all of its system operating positions." Item 2.4.3 paragraph 2 should be revised to state, "The responsible entity has provided 32 hours of emergency operations and system restoration training but the training has not been provided annually."
Response:			
Quality Training Systems	☑		See detailed comments below relating to Violation Level 2.2.1 requiring use of the Generic Task List provided as an attchment to the Standard.
Response:			
TAL		☑	No VSL should be high or severe for a requirement that is not a real time requirement. D2.4.1.1 - What if the entity reviewed Attachemnt A and did not identify anything else that was performed? What if they did identify several other items, but missed only one. These should not be violations. If the entity made a good faith effort, it should be compliant. The selection of a task from the list, or adding it to the list, is subjective for the entity. As such, how can a compliance team come in and apply another subjective criteria to the list? D2.4.3 - Grammatically incorect. Second paragraph should end " training has not BEEN provided annually."
Response:			

Question #8			
Commenter	**Yes**	**No**	**Comment**
Madison G&E		☑	a) In 2.1.3, under VSL, it is possible that the list of Emergency Operations Topics exactly fits an entity, and such entity should not be penalized for that. In 2.2.3, this implies that ALL of the subject areas must be met annually. If this is not the intent, it should be clarified. If this is the intent, this appears to be too demanding for each operator to meet all 42 subject areas in 32 hours. b) VSL's need to be vetted through the electric industry or drop them all together. Since a training violation does happen during realtime, the VSL should be low.
Response:			
Entergy (2)		☑	In general, the VSLs are extremely complex and take up more of the standard than the actual requirements, measures and compliance sections. Condense and simplify.
Response:			
ERCOT		☑	This part of the standard is not clean and simple. Plus, it's an administrative standard and should not carry moderate to high violation levels. Also, lack of documentation should be a low violation. High and Severe violations should be reserved for entities who do not have training programs, or their programs are not maintained with adequate staff.
Response:			
Southern		☑	Under Violation Severity Levels, it is not obviously apparent that missing two of the five phases of a SAT should have the same severity as not having a SAT program at all. There should be some differences in violation severity between the two.
Response:			
Allegheny Power			
AEP		☑	2.2.1 - Renumbering of R1.1 and making it R2, thus separating the reliability task identification requirement from the SAT requirement, would be an improvement, and would allow two different violation security levels. 2.3.1 & 2.4.1 - Violation of SAT should be "lower", not "high" or "severe". An entity may produce adequate training with proper performance results without using SAT. Many entities produce qualified operators today without SAT. SAT (ADDIE) should be a guide attached to the standard or as a reference document, but should not be the standard. The violation should be on "not performing training for identified tasks", rather than how you created the training. If training produces the desired results, how you did it should not be the measure, but rather, the measure should be satisfactory operator performance capability to perform.

Question #8			
Commenter	**Yes**	**No**	**Comment**
			2.3.1.1 - the "Note" refers to R1.2, but there is no R1.2.
Response:			
ATC		☑	ATC does not agree with the assignment of High (Violation Severity Level) for a failure to use one of the five phases of a SAT. In practice if an entity does not use one of the five phases of a SAT in one training program then it will be assessed a high violation severity level. ATC believe that this designation is too great for the violation. NERC needs to look at the number of training programs and to the extent of the failure. Did every training program fail to include one of the five phases or was this only in a small minority of the programs. We would ask that the SDT develop more reasonable violations severity levels for this standard.
Response:			
BCTC		☑	The way the Violation Severity Levels are written are too complicated to follow and many are open to interpretation. As an example the words for the High level say in part ".....is missing one or more significant elements". what does the word significant mean to the person who is reading this......significant to whom, the audit team; too vague? We do not agree with any of the words written for the severity levels; the standard and requirements are short on words and severity levels have explicit severity levels that are not detailed in the requirements. We again want to say that this will be a huge onerous task to place on any entity based on the implementation plan and we cannot support it.
Response:			
CAISO		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. We note that a SEVERE VSL is applied for missing evidence of using two phases of the SAT; as well as applying a SEVERE VSL for not having a program at all. This would result in an organization that inadvertently is missing evidence being held to the same VSL level as an organization that consciously has no program at all.
Response:			
CenterPoint			
NIPSCO	☑		
NPCC RCS		☑	Requiring a training program subject to following 5 Systematic Approach to Training

Question #8			
Commenter	**Yes**	**No**	**Comment**
			(SAT) principles seems overly perscriptive and why would it be a severe violation severity level not to follow these or subset thereof. NPCC Participating members can accept 5 training principles but the entire SAT seems unnecessary. If NERC intends to adopt the SAT, in its entirety, it needs to clarify and educate the industry before incorporating it into a standard.
Response:			
PG&E (1)			
PG&E (2)		☑	The violation severity levels are to complicated. The violation severity levels are extremely defined in comparison the requirements. To comply with the violation severity levels would be a huge onerous task on any entity based on the implementation plan.
Response:			
PJM		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. PJM would note that a SEVERE VSL is applied for missing evidence of using two phases of the SAT; as well as applying a SEVERE VSL for not having a program at all. This would result in an organization that inadvertently is missing evidence is held to the same VSL level as an organization that consciously has no program at all.
Response:			
SRP		☑	The severity levels are too extreme. Section 2.3.1 states a HIGH severity for missing one out of five phases of the SAT process. An entity that is using four of the five, which is an 80% use rate, should not be penalized with a HIGH severity violation. The severity for this ocurrence should be reduced to at least a MODERATE. Section Section 2.4.1 states a SEVERE severity for missing two out of five phases of the SAT process. An entity that is using three of the five which is an 60% use rate should not be penalized with a SEVERE severity violation. The severity for this ocurrence should be reduced to a HIGH severity. The SEVERE severity should be used for missing three of the five SAT phases. In summary: Moderate Severity: Missing one of the five SAT phases. High Severity: Missing two of the five SAT phases. Severe Severity: Missing three of the five SAT phases.
Response:			

Question #8			
Commenter	**Yes**	**No**	**Comment**
SDG&E		☑	The requirement for emergency training is in multiple standards (e.g. PER-002-0 R4. This then leads to the potential for multiple violations for the same deficiency. This training requirement should only be in one standard.
Response:			
We Energies		☑	Many of the violation severity level statements need to be simplified/clarified (similar to M1). 2.2.3 - R3.1 requires the training be from topics in Attachment B, so there would be no emergency training if the training was not from Attachment B topics. 2.3.3.1 The current wording of R3.1 does not allow training in principles, only drills, exercises, or simulations. See question #11. 2.4.3 The statement after OR is unnecessary. If 32 hours were not provided annually then the first statement applies.
Response:			
Garland		☑	Same answer #7.
Response:			
HQT		☑	Requiring a training program subject to following 5 Systematic Approach to Training (SAT) principles seems overly perscriptive and why would it be a severe violation severity level not to follow these or subset thereof. NPCC Participating members can accept 5 training principles but the entire SAT seems unnecessary. If NERC intends to adopt the SAT, in its entirety, it needs to clarify and educate the industry before incorporating it into a standard.
Response:			
IESO		☑	(1) 2.1.3 See our comment under Q6 that is related to this violation severity level. (2) We are unable to offer comments on the VSLs associated with not following or missing any steps in the SAT program. We not do see adopting and following a SAT approach to develop a training program should be a requirement. Please see our comments under Q11.
Response:			
ISO New England		☑	Requiring a training program subject to following 5 Systematic Approach to Training (SAT) principles seems overly perscriptive and why would it be a severe violation severity level not to follow these or subset thereof. ISO-NE can accept 5 training principles but to require only SAT seems unnecessary. This goes against the principle pf

Question #8			
Commenter	**Yes**	**No**	**Comment**
			telling the industry WHAT to do, not HOW to do it.
Response:			
Manitoba Hydro		☑	The Violation Security Levels are too complex to follow.
Response:			
MISO Stakeholders		☑	In general, we do not support the application of any violation severity levels because the VSL guideline has not been vetted through the industry. We do have the following specific issues and concerns as well. 1. The VSLs try to cover so many scenarios that they are confusing. We had enough trouble understanding them that we are concerned we have not identified every specific issue with them. 2. In the Moderate Violation Severity Level, section 2.2.2 creates a de-facto requirement on the training schedule because the training based on the mis-match in performance is required to be in the current schedule. What if a responible entity's schedule is updated every quarter and only goes out 3-6 months? They could still train on this in months 7-12 but this compliance element would find them in violation because it was not in their "current schedule". 3. We do not agree that a lack of documentation should be considered a high violation as described in section 2.3.1 of the High VSL. Lack of documentation should be a lower violation. 4. Sections 2.3.1.1, 2.4.1.1 and 2.2.1 duplicate one another but are in different VSL.
Response:			
MRO		☑	Too complex. Don't need to list five phases again and again.
Response:			
SPP ORWG		☑	The proposed severity levels are too complicated and need to be simplified.
Response:			
WECC OTS		☑	WECC OTS feels the violation severity levels are to complicated. The violation severity levels are extremely defined in comparison the requirements. To comply with the violation severity levels would be a huge onerous task on any entity based on the implementation plan.

Question #8			
Commenter	**Yes**	**No**	**Comment**
Response:			

9. Do you agree with the Implementation Plan that phases in compliance with the Requirements over a three year period? If not, please explain in the comment area.

Summary Consideration:

Question #9			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		
Florida Power & Light	☑		
FRCC	☑		
LCRA		☑	If I started on this today, it would take me longer than that to create all these new requirements. In order to meet this requirement, I would have to drop all other responsibilities.
Response:			
NYISO		☑	R3 is in effect now under PER-004. There is no need for a phase in. On the other hand R3 has no place in a systematic approach to training and should be deleted. If, and only if, R1, R2, R4, Appendix A and Appendix B are rewritten along the lines suggested in this comment form, the effective dates would be viable.
Response:			
OVEC		☑	The implementation plan should be simplified to allow for clearer understanding and easier tracking. Suggest that R3 become effective immediately upon regulatory approval since the 32 hours of annual emergency operations training is currently required in PER-002, R4. Suggest that R2 become effective January 1 in the first year following regulatory approval because an effective date that would allow for less than a full calendar year of implementation does not give an entity time to thoroughly assess annually the training needs of each System Operator position. Suggest that R1 and R4 become effective January 1 the second year following regulatory approval. The suggested times balance the timely implementation of the standard to maintain and enhance reliability, while allowing entities ample time to achieve compliance with the requirements, and is a simpler and more straight forward implementation plan that is easier to understand and track.
Response:			
PHI	☑		
SMUD	☑		

Question #9			
Commenter	**Yes**	**No**	**Comment**
APS		☑	See Item 4 above.
Response:			
Santee Cooper	☑		
Avista	☑		
Entergy (1)		☑	R3, 32 hours of training, may be effective the first day of the first quarter but compliance with that requirement will take up 10 weeks to train all the system operators due to shift rotations and training schedules. Please make this change for compliance. The timing for implementation of the other requirements seems out of order. First the SAT needs to be performed, R1. Then, the capabilities of the operators need to be verified R4 before a mis-match can be performed R2, from which training needs are identified and implemented. We suggest it will take 18 months to complete R1, followed by 18 months to complete R4, and finally a third 18 months to complete R2.
Response:			
FirstEnergy		☑	
Quality Training Systems	☑		
TAL	☑		
Madison G&E		☑	a) Entities have established training programs per Regulatory Approved Standards. Proposed Effective Date, 5.1 is the only parlell, carry over requirement from a Regulatory Approved Standard (PER-002-0, R4) to this proposed standard. This time frame is workable. b) Proposed Effective Date, 5.2 is unclear (see comments of 2.a, above), so an effective date can not be proposed yet. c) Proposed Effective Date, 5.3 for the proposed SAR contains over 370 tasks for operators and the time line is too aggressive. Registered Entities will need to be trained in the Systematic Approach to Training process, set up their own processes, convert established training to the SAT process, create new training and start to give training to System Operators. Budgets will need to be forecasted, personnel will need to be tasked with the training process (most companies have a small training department), this will take an extream amount of time and cost are unknown at this time.

Question #9			
Commenter	**Yes**	**No**	**Comment**
Response:			
Entergy (2)		☑	PER-005-1 Proposed effective dates: R1 & R2 should be implemented simultaneously, since R2.2 cannot be performed until R1.1 is completed. However, 36 months to have a training program implemented is reasonable.
Response:			
ERCOT		☑	R1, R2 & R4's timeline should have an additional time, at least another year, added to allow for budget cycles, hiring & traininig trainers. Additional personel will be required in many cases and these positions will need to be budgeted before they can be filled. Once filled, then the work to develop a training program begins. Depending on the approval date, a company's budget cycle may be well underway and beyond the point of change and thus delay their ability to succeed within the current timelines.
Response:			
Southern	☑		
Allegheny Power		☑	The implementation schedule is too aggressive with regards to Requirement 2. Requirements 1 and 4 should be implemented completely before Requirement 2. A more reasonable implementation schedule is 18 months for Requirement 1 followed by 18 months for Requirement 4 and then an additional 18 months for Requirement 2.
Response:			
AEP		☑	R2 – We agree with the 36 months but recommend the implementation time for R2 be changed from 18 to 36 months as R2.2 is conflicting with R1 implementation time. R2.2 - This part of the standard requires the assessment to include analysis of new or revised tasks for the specific company/entity and job position, which is specified for task identification in requirement R1.1. This is conflicting since the implementation plan time for R2 is 18 months, and the implementation time for R1, to have the task list identified with comparison to the reliability tasks of Attachment A, is 36 months.
Response:			
ATC	☑		
BCTC		☑	While we appreciate the time frames for implementation of some requirements at 18 months and 36 months would be helpful to allow implementation of these requirements we do not support the requirements as they are written as they are too onerous and not achievable in the time frames without hiring many more staff and applying lots of money to the make it happen. So if we do not agree with the Requirements, we cannot agree to the time phases.

Question #9			
Commenter	**Yes**	**No**	**Comment**
Response:			
CAISO		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. We do not support this standard as written, and therefore do not agree with the implementation schedule at this time.
Response:			
CenterPoint		☑	CenterPoint Energy agrees with the implementation plan for R3; however, we disagree with the implementation plan for R1, R2, and R4. If PER-005 is modified to align itself with the other NERC training programs that certify system operator competency, we would agree with a three year implementation period.
Response:			
NIPSCO		☑	Since the training program with not be completed until the end of the three year period, assessments of personnel could not begin until after the completion of this development.
Response:			
NPCC RCS	☑		
PG&E (1)			
PG&E (2)	☑	☑	The implementation plan would be acceptable if NERC can develop the Standard so that they are clear and specific.
Response:			
PJM		☑	The Compliance elements of this standard should be postponed until the requirements are agreed to. PJM does not support this standard as written, and therefore cannot agree to any implementation schedule at this time.
Response:			
SRP	☑		
SDG&E		☑	The implementation for R3 should allow an organization time to put any new training requirement into its regular training plan. Put that it needs to be included in the next years annual training program.
Response:			
We Energies		☑	Implementation of R2.2 at the 18 month point requires that R1.1 (implemented in 36 months) be completed first.
Response:			

Question #9			
Commenter	**Yes**	**No**	**Comment**
Garland		☑	It is an unreal expectation that a small utility will have the resources to comply with the requirements stated in R2 and R4.
Response:			
HQT	☑		
IESO		☑	We have a major difficulty with the standard as written. We are therefore unable to agree on the implementation plan.
Response:			
ISO New England	☑		
Manitoba Hydro	☑	☑	I think the plan is okay but if it has a medium risk factor then is that being understated and should we not be starting immediately.
Response:			
MISO Stakeholders		☑	If the standard were simplified, it could be phased in more quickly.
Response:			
MRO	☑	☑	If there is really a MEDIUM risk to the system perhaps the implementation plan should be accelerated. On the other hand, the implementation schedule may be overly aggressive if significant modifications to the Job Tasks are required.
Response:			
SPP ORWG		☑	Requirement 1 should be effective 18 months after the first day of the first quarter following regulatory approval and Requirements 2 and 4 should be effective 36 months after the first day of the first quarter following regulatory approval.
Response:			
WECC OTS	☑	☑	The WECC OTS questions the implementation plan, when they do not agree with the current requirements. However, the implementation plan would be acceptable if NERC can develop the Standard so that they are clear and specific.
Response:			

10. Are you aware of any conflicts between the proposed standard and any regulatory function, rule/order, tariff, rate schedule, legislative requirement, or agreement? If not, please explain in the comment area.

Summary Consideration:

Question #10			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	
Florida Power & Light		☑	
FRCC		☑	
LCRA		☑	
NYISO		☑	
OVEC		☑	
PHI		☑	
SMUD		☑	
APS		☑	
Santee Cooper	☑		
Avista	☑		
Entergy (1)		☑	
FirstEnergy			FERC 693 (par. 1359) directive to include the Generator Operator has not been addressed by this standard.
Response:			
Quality Training Systems			No comment.
TAL		☑	
Madison G&E	☑		a) In NERC's Reliability Standards Development Plan dated Nov 30, 2006 (pg 3 of 21), (pertaining to FERC Order 672) states "the Commission states that a proposed reliability standard must be designed to achieve a specific reliability goal and be clear and unambiguous regarding what is required and WHO is required to comply". The STD will need to rewrite Applicability 4.2, (use of the words "and their delegates") do to the ambiguous personnel requiring training other than certified system operators.

Question #10			
Commenter	**Yes**	**No**	**Comment**
			b) R4.2 states the standard applies to System Operator positions listed under R4.1 and "their delegates who can directly, or through communications, impact reliability by producing a real-time response from the Bulk Electric Systyem". In NERC's Personnel Certification and Governance Committee (PCGC) Charter (approved May 2, 2007), Section 2, 1.a. includes that the PCGC sets the "requirements for personnel certification, maintaining certification, and recertification". The PER-005-1 SDT does not have the authority to require non NERC Certified personnel to be trained under a NERC Standard. The PCGC establishes who must be NERC Certified.
Response:			
Entergy (2)		☑	
ERCOT		☑	
Southern		☑	The question should have stated: If yes, please explain in the comment area.
Response:			
Allegheny Power		☑	
AEP		☑	
ATC		☑	
BCTC		☑	
CAISO	☑		The lack of objectivity in these requirements will conflict with labor union contracts. In addition the draft standard does not meet NERC or FERC requirements regarding clarity and measurability; nor does the draft meet the FERC objection to fill-in-the-blank standards.
Response:			
CenterPoint			
NIPSCO		☑	
NPCC RCS	☑		The lack of objectivity in these requirements may conflict with labor union contracts. ie confidentiality issues of performance reviews.
Response:			
PG&E (1)			
PG&E (2)		☑	

Question #10			
Commenter	**Yes**	**No**	**Comment**
PJM	☑		The lack of objectivity in these requirements will conflict with labor union contracts. In addition the draft standard does not meet NERC or FERC requirements regarding clarity and measurability; nor does the draft meet the FERC objection to fill-in-the-blank standards.
Response:			
SRP		☑	
SDG&E			
We Energies		☑	
Garland		☑	
HQT	☑		The lack of objectivity in these requirements may conflict with labor union contracts i.e. confidentiality issues of review.
Response:			
IESO		☑	
ISO New England	☑		The lack of objectivity in these requirements may conflict with labor union contracts (i.e. confidentiality issues of performance reviews).
Response:			
Manitoba Hydro	☑		There may be issues with some unions and its agreements.
Response:			
MISO Stakeholders		☑	
MRO			(It seems the last sentence of this question is incorrectly phrased. Shouldn't "not" be replaced with "yes"?) There may be issues with existing union agreements.
Response:			
SPP ORWG	☑		Has the SDT taken into consideration dealing with bargaining units when conducting the assessments on individual System Operators. In some bargaining units, individual performance assessments have been eliminated.
Response:			
WECC OTS		☑	

11. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard PER-005.

Summary Consideration:

Question #11	
Commenter	**Comment**
Ameren	No comment.
Response:	
Florida Power & Light	Overall,I am in support of the development of a training standard to ensure personnel responsible for the real time operation of the BES to meet minimum knowledge and competency levels. However, I would recommend that any training requirements noted in NERC Standards should be identified only in the System Personnel Training Standard. This standard should apply to System Operating Positions only - not by individual system operators.
Response:	
FRCC	Overall, FRCC is supportive of the development of a training standard to ensure personnel responsible for the real time operation of the BES to meet minimum knowledge and competency levels. However, the FRCC recommends that any training requirements noted in NERC Standards should be identified only in the System Personnel Training Standard. How is a "new" employee handled? If I hire an operator and he gets NERC Certified in November (or later) I feel I should not have to complete all 32 hours of emergency training. This standard should be by position only - not by system operators.
Response:	
LCRA	To recap, the creaters of this standard have done a good job. My problem is not so much with the standard itself, as it is with the completely unreal expectation that the resources, money, and time exist to do all of this. Some further points: R.2- How are we supposed to accomplish this? Test each operator on each task anually? I spent 9 years in nuclear power operations and I did not get tested on each critical task the entire nine years. I was responsible for all critical tasks, but annually I was tested on a few randomly selected ones. That is a much better way to manage such a program. From the generic task list for Transmission:

Question #11	
Commenter	**Comment**
	#5: Not performed by Transmission System Operators, this is done by support staff #18: Not performed by Transmission System Operators in ERCOT #27: Not performed by Transmission System Operators #45: Not performed by Transmission System Operators in ERCOT, this is done by support staff #61: What if your utility has no HVDC? #67: In ERCOT, Transmission System Operators do not redispatch generation. This function is performed solely by the QSE. The only case where this would not hold true would be a blackstart. #70, #71, #72, #73, #79, #81: Since ERCOT is a deregulated market none of these functions are performed by Transmission System Operators at LCRA. The standard mentions that a given organization is responsible for these generic tasks as well as any other self-identified ones. Use your common sense, if you give people the option of adding to their work load by adding elements to the list, basic human nature will lead people to not do so. Why would they want to create work for themselves when this standard would already be making their jobs incredibly burdensome? Conversely, if entities are allowed to drop some of the generic items off the list what you will see is individual utilities paring this last down to something manageable. What we have here is a proposal to implement a standard without, in my opinion anyways, a thorough assessment of its impact. The basic idea is sound-a mandate for a systematic approach to training. The devil is in the details. I believe there is no concept of the time and resources that exist in this industry on the part of those who created this standard. You can mandate it, but it does not meant that those of us in the positions of responsibility will get the money/resources it would take to implement such a massive undertaking. The smaller utilities would need real help in making this happen. If NERC is bent on pushing this standard through then it should step up to the plate with regional training, templates, standardized forms, etc-all the things that will be needed to make this happen. This new standard would amount to an unfunded mandate making compliance a very difficult proposition for those of us at the end of the pointy stick. In fact, I would personally consider moving into some other area out of training in order to not be liable.
Response:	
NYISO	Requirement R1.2 should be deleted in its entirety. It mandates through "shall" that "all" the tasks in Attachment A be included in the company specific task list. Attachment A includes meaningless, redundant and poorly worded task definitions. If NERC wishes to create a separate document to aid entities in developing a company-list, that would be OK. But Attachment A, as written, is worthless and misleading definitions of tasks. The Attachment A has no place in a standards document unless each and every item on those lists is

Question #11	
Commenter	**Comment**
	mandatory. Both Attachments A should be deleted or completely reworded. As written, it will never stand up in court as valid task definitions. Here are examples of poorly worded tasks from the NERC Generic Task Lists: Emergency Operations, which I will be mandated to include in my company specific task list Consider items 1-10 on that list. 1 Request emergency energy upon loss of a resource 2 Respond to capacity deficiency 3 Respond to loss of energy resources within allowable regional or pool timeframe 4 Prepare for a capacity emergency by bringing on all available generation 5 Prepare for a capacity emergency by postponing equipment maintenance 6 Prepare for a capacity emergency by scheduling emergency energy purchases 7 Prepare for a capacity emergency by reducing load 8 Prepare for a capacity emergency by initiating voltage reductions 9 Prepare for a capacity emergency by requesting emergency assistance from other systems 10 Schedule available emergency assistance with as much advance notice as possible given a capacity emergency The true tasks in these items have nothing to do with the causal event. Cutting out the phrase about "capacity emergency" will clarify those task statements 3-10 exceedingly. Cutting out the causal trigger for action, i.e. "Capacity deficiency", the measurable task #2 becomes "Respond to". Please provide an example of how one measures competency for the task "Respond to". In items 4-8, the competency task has nothing to do with the trigger to initiate the task. Dropping "Prepare for a capacity emergency by….", is not a task definition. "Bringing on all generation", "postponing equipment maintenance", "scheduling emergency energy purchases",

Question #11	
Commenter	**Comment**
	reducing load, initiating voltage reductions" (which is really a subtask of reducing load), "requesting emergency assistance from other systems", can be executed to resolve any number of issues besides capacity emergencies. The same tasks can apply to (1) preparing for and (2) resolving - all the subsets of SOL and IROLs. How is the task "request emergency energy" in item 1 different from "scheduling emergency energy" in item 6, or "schedule available emergency assistance" in item 10"? Please explain. The same exercise can be applied to items 15-24 on that list. 15 - Manually shed load to alleviate system emergency conditions 16 - Following the activation of automatic load shedding schemes, restore system load as appropriate for current system conditions and in coordination with adjacent systems 17 - Following the activation of automatic load shedding schemes, shed additional load manually if there is insufficient generation to support the connected load 18 - Following the activation of automatic load shedding schemes, monitor system voltage levels to ensure high voltage conditions do not develop 19 - Following the activation of automatic load shedding schemes, monitor system frequency to ensure high frequency conditions do not develop 20 - Following the activation of automatic load shedding schemes, monitor the performance of any automatic load restoration relays 21 - Following the activation of automatic load shedding schemes, resynchronize transmission at preplanned locations if possible 22 - Following the activation of automatic load shedding schemes, disable automatic under frequency relays if system conditions warrant 23 - Direct distribution providers to shed load when required for system reliability 24 - Use manual load shedding to prevent imminent separation from the Interconnection due to transmission overloads or to prevent voltage collapse "Following the activation of automatic load shedding schemes" has no place in an outcome oriented, measurable task definition. It makes no difference to the operators' task how the load was shed. Is the manual load shed task in 15 any different from the manual load shed task in 24? Are transmission overloads and voltage collapse in task 24 not included in task 15 "emergency conditions"? Please explain.

Question #11	
Commenter	**Comment**
	Does restoring system load task in 16 have any connection to how the load was lost? Is restoring load lost by UFLS, different from restoring load for manual load shed, or load trip, or restoration? Please explain. Do you only monitor voltage levels following a UFLS event? Do I need different tasks to monitor voltage for load pick-up, load drop-off, line switching, line tripping, generation tripping, capacitor switching, reactor switching, phase shifter operations, HVDC operations, and interchange schedule changes? For each of these tasks, will I need a procedure for the auditors to verify? Please explain. Do we only resynchronize transmission at pre-planned locations after UFLS events? Do I need to define different tasks for resynchronize transmission at pre-planned locations after a maintenance separation, during a system restoration, etc.? Please explain Attachment B is severely flawed and redundant The list in Attachment B has no place in a standards document unless each and every item on those lists is mandatory. Attachment B should be deleted or seriously reworded. It will never stand up in court. A1) "Emergency Drills and Responses" will capture: All of section B "Operating Policies relative to Emergency Operations" D4) responding to imminent voltage collapse D5) SOL: and IROL D6) DC operations during system emergencies All of section B, D4, D5 and D6 should be removed in this standard that addresses a systematic approach. D8 & D9. There is no distinction between "congestion management" and "line loading procedures" Remove D8 as redundant in this standard that addresses a systematic approach. What is the difference between "congestion management" and "line loading procedures"? Please explain.

Question #11	
Commenter	**Comment**
	D11: Assuming that "tie line operations" means CPS control state that. If you intend it to mean another form of line loading control, delete it. If you mean these to be different items, please clarify. A5 & D2; There is no distinction between A5 and D2. Remove D2. A5: System protection D2: Special protections systems What are "special protections systems" if not an instance of "system protection"? Please explain. A4 & D3: There is no distinction between A4 and D3. Remove D3 A4: operations during unstudied conditions d3: special operating guides What is if the function of "special operating guides" if not to address "operations during unstudied conditions"? Please explain.
Response:	
OVEC	The statement in Applicability Section 4.2 is too broad. It could be interpreted to include switchmen performing switching because switchmen can "impact reliability by producing a real-time response form the Bulk Electric System." This interpretation will not achieve industry consensus for the standard. The statement should be revised to repeat requirements R2 and R2.1 of PER-002 which states that "Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in: Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System." This statement has the correct narrow focus, is easily understood, and is currently implemented by the entities. It is confusing in R2 why the word "position" was used rather than the word "person" and why was the word "capability" used at the end of the sentence. As currently worded, it is not clear what R2 is trying to require. The requirement seems to be asking an entity to "determine mismatch between acceptable and actual performance capability for a position." What does that mean? The implementation of that interpretation does not seem feasible for the "capability of a position." It would seem the intent should be to determine the mismatch between acceptable and actual performance for an individual operator which R4 of the standard basically states. Suggest deleting

Question #11	
Commenter	**Comment**
	R2, R2.1 and R2.2 and adding specificity to R4 described below. R4 does not indicate how often an entity should verify capabilites of its Sytem Operators. Do entities only need to verifty capability of an Operator one time for each task? What if the task is rarely performed, how often should verification take place? What if the task is performed daily, how often should verification take place? The lack of a specified frequency to verify capability creates a requirement that provides no improvement to the reliability of the Bulk Electric System. In R3 delete "and system restoration training" because this type of training would be considered emergency operations already. Delete R3.1 and Attachment B because the added specificity will not improve the type or scope of emergency training. Delete R3.1.1 because by just having a list will not improve emergency training or improve the reliability of the Bulk Electric System. This proposed standard and several other standards appear to be an overreaction to the August 14 blackout. It seems to fall back to the specious argument that is if something happens, someone must have been responsible for the problem . Why are we unable to place the blame on the system for the problem, even if the system was the problem? There has been no assessment or evaluation of the effectiveness existing training programs required by PER-002, R3 that has been in affect for over two years. Why create a standard to mandate a new training program when no assessment has been made of the effectiveness of existing training programs? The work to create a new training standard is not a judicious use of resources in order to strengthen the reliability of the bulk electric system. The argument that FERC has mandated SAT-based training programs in its order does not preclude the possibility that the FERC conclusion is wrong and unneccesary. This standard goes beyond requiring a new training program. The standard seems to dictate the material on which operators are to be trained and how they are to be trained. The NERC operator certification program already determines that operators possess the minimal requirements to reliably operate the bulk electric system. Why should a training program duplicate the certification process? Currently there is ample incentive to have operators trained on company-specific tasks. An operator who is not capable of performing company specific task will not remain an operator at that company. Many of the tasks listed in Appendix A do not seem to be reliability related and some would seem to be beyond the scope of a system operator position. For example, Item 18, says "Ensure that transmission contract paths are not exceeded." This item is more of a regulatory or business

Question #11	
Commenter	**Comment**
	requirement than a reliability concern. Item 42, "Prepare daily reports and logs generated to meet company and regulatory requirements." This item may be important, but it is not important for reliability. Item 65, "Implement specified procedural actions in the event of a FERC Standards of Conduct violation." How is this item reliability related? Item 9, "Interpret relay targets, during forced outages." This item would be the responsibility of a system protection engineer who would provide guidance to the system operator and would not be the sole responsibility of the system operator. In rebuttal to the "Background Information" provided above, work on this proposed training standard should cease and the standard should not be implemented for the following reasons: 1. Training is currently being provided to NERC Certified System Operators as a part of the NERC conitinuing education requirements for system operators and as also required in PER-002, R3. 2. Emergency Operations training is currently required in PER-002, R4. 3. Entities are currently allowed to determine and develop training based on individual training needs to support operation of the Bulk Electric System. 4. The language of the standard is too prescriptive especially, but not limited to, the inclusion of Attachment A and Attachment B. 5. Entities do not need a common starting point for training because of the extreme operational differences between entities. 6. Entites currently implement successful training programs as required by PER-002, R3. 7. The conclusion and assumption from the August , 2003 blackout investigation that Sytem Operators were not prepared to react in a manner that preserves the reliability of the interconnection is not correct. The operators were indeed prepared and were reacting to the events before the August, 2003 blackout in a manner to preserve the reliability of the interconnection by using the best data and information available to them. System Operators today are trained to perform tasks assigned to their position.
Response:	
PHI	No comment.
SMUD	All training requirements per standard should be cross referenced and included in a PER attachment or could even be excluded from the individual standards. On the cover letter, SMUD disagrees that the verification of qualifications for people developing / delivering training should be eliminated. Also, SMUD disagrees on the elimination of the requirement addressing maintenance of the system operator training program. SMUD believes the methodology used to perform the analysis phase of a systematic approach to training (SAT)should be required in the standard not just the phases of the SAT process.
Response:	

Question #11	
Commenter	**Comment**
APS	We question the Applicability of this standard to "delegates" referenced in 4.2. Depending on how this requirement is interpreted, the scope of the training project we're undertaking could grow exponentially. The R.1.1 requirement seems to demand that entities use the Generic Task List during their analysis phase. If another commercially available list is currently being used, is it invalidated by this standard? The details provided in R2.1 and R2.2 could be easily included in the verbiage of R2 for simplicity. The details provided in R3.1 and R3.1.1 could be easily included in the verbiage of R3 for simplicity. Draft 2 of PER-005-1 is a big improvement over Draft 1.
Response:	
Santee Cooper	The System Personnel Training Standard should address training that is required for reliable operation of the BES. It should not dictate how a company must implement its actual training program.
Response:	
Avista	No comment.
Entergy (1)	The draft standard extends the requirements to an undefined phrase: "delegates who can directly, or through communications, impact reliability by producing a real-time response from the Bulk Electric System". We do not understand the meaning, scope or extent of who or what constitutes "delegates" that might fall under this standard. We request this phrase be deleted from this and all similar standards. We also request the authors not include any other phrases like "delegates" or any other similar attempts to extend job functions of other RC, BA or TOP positions into the definition of System Operator. R1.1 requires the creation of a company specific list of BES reliability-related tasks, the creation of which could be considered part of R1 itself and does not need to be a separate requirement. In addition, an entity will be penalized twice for not developing this list, once for R1.1 and penalized again for violating R1. Therefore, R1.1 should be deleted and considered part of R1, performing the Analysis phase of the SAT process. SHOULD WE SUGGEST R1.1 BE DELETED, OR SHOULD IT BE A SEPARATE REQUIREMENT? LEAVING R1.1 AS IT IS COULD BE CONFUSING. The intent and meaning of the wording "acceptable" and "actual" performance capability used in R2 as they are applied to a System Operator Position is not clear . Please clarify the intent and meaning of R2. A position can have tasks assigned to it with acceptable or defined, performance criteria. A

Question #11	
Commenter	**Comment**
	position can not have "actual" performance capability; a person performing that task can have "actual" performance capability. If the intent of R2 is to determine the mis-match between a persons actual performance capability of a task and the acceptable performance criteria for that task then please so state that one part applies to a person and one part to the position. If it is not the intent, then please clarify the meaning of this section. PER-004-2, as revised, contains two requirements: one to maintain staffing 24/7, and the other to place attention on SOLs, IROLs and inter-tie facility limits, and to ensure protocols are in place. There are no measures for these three requirements. Please add measures for these three requirements.
Response:	
FirstEnergy	FE has the following additional comments: 1. This standard requires the use of the SAT process, yet it contains no requirement for trainers to be trained in this process. This train-the-trainer requirement is necessary to ensure an effective implementation process throughout the industry. This should be remedied prior to this standard becoming effective. 2. In R3, the phrase "...at least 32 hours annually of emergency operations and system restoration training" is written incorrectly and does not coordinate with its measure, M3. We suggest changes to the phrase in both R3 and M3 to read "...at least 32 hours annually of emergency operations training which includes system restoration training". 3. In R1, the last part of the statement should say "...System Operator positions." and not "...System Operators." This would then be consistent with the rest of the standard. 4. In Attachment A, Items #2 and #4 are duplicative. This should be corrected. 5. It is not clear how R4 would be acceptable from a compliance standpoint. The SDT should add verbiage to clarify this requirement. The measure for this requirement (M4) doesn't add any value. 6. Measures should not add requirements. We believe that M1.2 is dictating more requirements than R1 intends when it states "Design and development of training materials that result in learning objectives and content that is derived from results of training analysis". The SDT should remove this from the measures and re-evaluate the need for this statement in the standard.
Response:	
Quality Training	This comment relates to Requirement R1.1 that each Reliability Coordinator, Balancing Authority and

Question #11	
Commenter	**Comment**
Systems	Transmission Owner should use the generic task list in the Attachment to the draft standard as the basis for their own JTA. The task list contains important information and would certainly be useful as a guide for entities starting out on the JTA process, but we do not believe that the list is sufficiently well developed to be a required starting point. Quality Training Systems has developed and refined its generic task list for system operators over several years, making extensive use of NERC source documents and with advisement by Industry Experts. We recognize the difficulty in developing a coherent, well-categorized task list at a consistent level of detail, but we are nonetheless concerned at offering an industry standard that still offers considerable room for improvement. 1. Classification System The categorization scheme is difficult to follow in places as evidenced by the fact that closely similar tasks are listed in different Sections of the task list and - within a given section - under different Types of Activity. Consider, for example, the following tasks relating to voltage control: "Monitor and maintain defined voltage profiles to ensure system reliability." (Gen CC Ops 31 under Monitor) "Utilize reactive resources from transmission and generator owners to maintain acceptable voltage profiles." (Gen CC Ops 60 under Operating) "Monitor the voltages, and coordinate the reactive dispatch of transmission facilities, and the interconnections with neighboring systems." (Trans. Ops 34 under Operating) "Deploy reactive resources to maintain acceptable voltage profiles." (Trans. Ops 51 under Voltage) "Coordinate operation of voltage control equipment with interconnected utilities." (Trans. Ops 55 under Voltage) 2. Consistency There is a lack of consistency in the level of detail of the task statements. Some tasks are extremely general, and would be difficult to train in the stated form. For example: "Direct and/or regulate the operation of the transmission system" (Trans 15) "Enforce operational reliability requirements" (Gen CC Ops 47)

Question #11	
Commenter	**Comment**
	Other tasks are very specific and might be considered as steps in a larger task. For example: "Notify all affected areas that line loading relief has been requested, and that corrective actions are required" (Trans. 68) "Manually calculate net interchange when needed" (Int. 17) 3. Repetition Many tasks are repeated with closely similar wording or wording such that the more general statement includes the other more specific task(s). For example, compare :the following two tasks taken from different Sections of the Task list: “Implement system restoration procedures” (Gen. CC Ops 68): “Following a partial or total system shutdown, implement the appropriate provisions and procedures of the system’s restoration plan in a coordinated manner with adjacent systems" (Emer. Ops 50)” 4. Clarity A few of the task statements are unclear or poorly worded. Consider, for example; the following task, the intent of whiich seems to be captured in better-stated items elsewhere in the list: "Direct to the appropriate entities those options necessary to relieve reliability threats and violations in a reliability authority area” (Gen. CC Ops 55)
Response:	
TAL	A4.2 - "producing a real-time response from the Bulk Electric System" is not clear and unambiguous. Turning on a light switch (to power the runway landing lights for the highly trained pilots) produces "a real-time response". R3 - How is a "new" employee handled? If I hire an operator and he gets NERC Certified in November (or later) I feel I should not have to complete all 32 hours of emergency training. Attachment A - The removal or addition of any item(s) is subjective. While I understand it is only a starting point, whose subjectivity will be used when determining compliance to this standard. Many of these items are poorly worded if they are intended to be a measurable task. I will be paring the list down substantially to remove redundant requirements, and clarify the remaining.

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	Attachment B - Intro paragraph is not entirely true. This list must be modified per R3.1.1 and will then contain the "company specific" topics for Emergency operations. Although training, or the lack of, played a part in the August 14, 2003 blackout, it was not the only thing found to need improvement. This standard places the burden of improvement of operations of the BES on the training system for the system operator. This is unfair to the majority of entities and operators who have adequate training in place and are not afraid to shed load when needed. This has placed the emphasis on proper documentation instead of performance. It will be expensive and turn into a paperwork nightmare to implement and to audit. A Systematic Approach to Training is not required to have a good training program. It IS required to be a CEH provider for NERC Credential Maintenance. But NERC has maintained a very pointed separation of the Training Standard and the CEH program and Credential Maintenance. This standard is trying to apply the CEH provider requirements to ALL entity training programs. It should not be the default system for every entity. Implementation of this standard as written will be a nightmare to implement and audit. It will result in lots of money spent for very little return on investment. It will dilute the effectiveness of many good programs out there and I doubt will force any of the mediocre ones into being good ones.
Response:	
Madison G&E	Attachment A: Concerning General Control Center Operations Tasks, #22 (Monitor real-time market prices) should be removed, reliability is not based on economics. #58 (evaluate, test, and/or confirm the accuracy of reliability assessment tools) should be removed, this is not an operator task. Concerning Generation Tasks, #14 (publish next-day market results) it is redundant with #29. #48 (suspend automatic generation control as required) should be removed, it is part of #47. #58 (operate power facilities in compliance with environmental standards) should be removed, it is not a part of reliability. Attachment B: A.6, needs to be split into two topics, 1) Geomagnetic Disturbances on system operations and 2) Weather impacts on system conditions.

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Response:	
Entergy (2)	PER-005-1 Applicability 4.2 : is this meaning that an operator performing a function per an approved procedure or under orders from an RC/BA/TO have training and be under a training program as outlined? This may be excessive application of the training standard. One could speculate that each power plant operator could fall under this because they operate a unit with MW and MVAR output, which creates a real time response from the BES. PER-005-1 R3, 3.1, 3.1.1 : the words "and system restoration" should be removed unless the system restoration topics in Attachment B are required. As written, R3 and sub requirements imply that some of the 32 hours must come from system restoration training. If that is correct then state the number of hours. Note that the title of Attachment B contains the term "Emergency Operations Topics" only, even though system restoration topics are covered under Section C. PER-005-1 Attachment A General Control Center Operations Tasks, Item 22: Monitoring of real-time prices for accuracy should not be listed as a reliability-related task. Reliability and pricing are distinctly different. Is the intent to monitor the impact to reliability that real-time pricing is having? Generation Tasks Item 14: Publishing next-day market results should not be a reliability-related task. PER-004-2 Proposed Effective Dates: the bullets are extremely confusing and refer to requirements that aren't even listed. If approval of these standards deletes a pre-existing requirement immediately, there is no need to even mention it in this section (assuming that these standards are balloted together). Otherwise, list ALL of the requirements in the Requirements section and then the list of when they would no longer be in effect in the effective date section. PER-004-2 Compliance Monitoring Responsibility : Should this be the Compliance Enforcement Authority (as stated in PER-005-1)? PER-004-2 Compliance Monitoring: There is only a need to list the self certification. All requirements in the standards can be subject to monitoring under the other methods (spot check, periodic audit, triggered) and there is no need to list them here.
Response:	
ERCOT	***VERY IMPORTANT***Implementation of this Standard without a guiding document for a training program similar to what is provided by the Department of Energy or the U.S. Military who routinely apply SAT or Instructional System Design (ISD) processes leave too much open to the inerpretation of auditors.

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	VERY IMPORTANT: 4.2 needs to be re-worded so it is clear that the RC/BA/TO is not responsible for training personnel in other organizations to which it has delegated tasks. After 4.2, "delegates" is not mentioned in conjunction with RC/BA/TO as being responisble to implement this standard.
Response:	
Southern	No comment.
Allegheny Power	No comment.
AEP	R1 - We believe R1 should not mandate the approach to training, but should only mandate identification of reliability tasks and a training program that has objectives that support the reliability tasks. R1 attempts to eliminate informal and impromptu type training for initial and continuing training. Good, informal training should still be allowed in any training program, as the approach can still be proper and reap proper results, without having extensive documentation of a systematic process. Over the years, there have been many hours of informal training that has reaped satisfactory and above satisfactory results in performance and progression of system operators. Though SAT can be an improvement in some cases, it is not an improvement in all cases. SAT requirements should be a guide given as a reference document, but should not be a requirement and measurement of the standard. R1.1. - Typographical error. Transmission "Owner" should be Transmission "Operator". R3 – We believe requirement R3 should be for “NERC Certified System Operators” and offer those operators hired mid-year or who have hardships causing extended absences that prevent accumulating the required 32 hours, relief from the requirement. We suggest re-wording as follows or in some other fashion to offer relief for special circumstances as mentioned above: ----“Each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each NERC Certified System Operator with at least 32 hours annually of emergency operations and system restoration training. NERC Certified System Operators with only 6-9 months of on-shift operating time due to mid-year hiring or hardships shall be required 16 hours annually of emergency operations and system restoration training. NERC Certified System Operators who have less than 6 months operating time due to mid-year hiring or hardships shall be exempt from the annual emergency operations training requirement.”---- 2.3.3 - Violation Severity Levels – Reword in accordance with the suggested rewording of R3 requirement above to reflect NERC Certified System Operators and reduced hour requirements for special circumstances such as mid-year hiring or hardships.

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	R3.1. – The wording of requirement R3.3 in parenthesis "(provided in Attachment B)" infers all topics of the attachment must be included in the 32 hours annual emergency training, and does not take into account the requirement of R3.1.1. We believe the intent should be "selected topics" from Attachment B. We believe R3.1 should be re-worded as follows: ----"The emergency operations and system restoration training shall include the principles and procedures needed for recognizing and responding to emergencies, using drills, exercises or simulations of system conditions in subject areas selected from the responsible entity's applicable Emergency Operations Topics listing developed from Attachment B and according to the requirement of R3.1.1."------- 2.2.3 – Violation Severity Levels – Re-word to correspond to R3.1 rewording as follows: -----"The responsible entity provided the minimum 32 hours of training on emergency operations or system restoration, annually for all system operators, but some hours provided included topics not listed in the responsible entity's list required by R3.1.1.----- 2.3.4. – Violation Severity Levels – Reword as follows for clarity of intent: ----"The responsible entity has performed an assessment of its System Operator's Capabilities to perform each identified task that is on its company-specific reliability-related task list, for some but not all of its System Operators.
Response:	
ATC	The Standard requires applicable entities to develop a task list using Appendix A as a starting point. The standard allows entities to add and delete from the task list (Appendix A) as they determined necessary. So, would Applicability section (4.2) only apply if a TOP, BA or RC identifies a task and then delegates that task to a System Operator not covered under the Applicability 4.1? In other words, if a RC identifies a task in their list and then states that the task is performed by a non-RC System Operator, that delegate would then have to follow this standard. If this is the case, who will be audited by the Regional Entities to confirm that the delegated System Operator is complying with the standard? Would the delegated System Operator have to be registered with NERC as a user, owner or operator of the BPS? The topic of delegation of requirements has come up in other standards and it's our position that NERC should develop a solution to the issue instead of looking to the individual SDT to come up with individual solutions. In this case the Applicable Entities are allowed to develop their own list using Appendix A because of this ATC believes that no entities will fall under 4.2 of the Applicability section.

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	ATC request that 4.2 of the Applicability section be deleted from this standard.
Response:	
BCTC	NERC CE and Certification of System Operators as a requirement was a huge step in dealing with issues that came from the Blackout recommendations. Meeting that requirement was also a good step in requiring training for SO's that meets a SAT process. And the continued training for SOs that support Certification went a long way to meet the Blackout recommendations regarding restoration, simulation and situational awareness. NERC would be better served by working with companies and training providers to make NERC Continuing Education fit the SAT and make sure all are comfortable with using it all the time when dealing with CE to maintain Certification. When that is accomplished moving forward on all training requirements starting with a proper JTA and all other training using the complete SAT could be looked at. We believe we are many years away from that.
Response:	
CAISO	It appears that the intent of this Standard is to standardize and clarify what is and is not appropriate training materials for acceptance into the NERC Continuing Education Program. This is not well understood by the industry. If this is indeed the case, the CAISO supports such an effort. The way the existing draft is being interpreted by the industry, however, is that this will be an additional requirement, over and above (and possibly in conflict with) the NERC Certification maintenance requirements currently contained in the NERC Continuing Education Program. The CAISO agrees that: - Training is a critical function for our industry. - NERC should mandate training time (i.e. minimum number of Continuing Education hours - limited to predefined critical functions) be required to ensure operators are provided experience with critical tools and procedures necessary to meet NERC's reliability standards. This could be coupled to maintaining NERC Operator certification. That would innocent operators to take the training or risk losing their personal certification, and would incent the organizations to ensure the training or risk not complying with the standard to use only-NERC certified operators. - General in-house training programs must be permitted to be structured to the varied ad hoc needs of the given organizations, their tools and their environment, and not subject to NERC standards. - Critical training be provided by accredited programs, and that NERC may desire to accredit programs used to provide CEH on those critical topics (e.g. Emergency Operations; Blackstart).

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	- the result of a Training standard should be an operator that is prepared to handle that operators system; the result should NOT be the production and storage of paperwork. The CAISO does not agree that: - It is necessary that every organization has its own accredited program. As written, R1 requires that responsible entities complete the five phases of a systematic approach to training (SAT), which includes analysis, design, development, implementation, and evaluation) to establish a new or modify an existing training program. We do not agree that this should be a requirement. The requirement should be for the responsible entity receive training to help system operation personnel to acquire the competency to perform the applicable tasks pertaining to the RC, TOP and BA functions that the entity is responsible for or assigned. The IRC neither endorses nor disapproves the SAT process as a good approach> However, how any training program is arrived at (i.e. what approach it takes) is not important and should not be a standard. If so inclined, NERC itself could offer an SAT-based Training program. How could one make an argument that using other approaches to arrive at a training program that (a) list the tasks and competency level required to perform the task, (b) include the minimum requirements stipulated in this standard such as the 32 hours emergency training, (c) has provision for a training schedule, review process, etc. is not an acceptable approach? Performance and capability are subjective ideas. Given all of the tests and training, no one can predict how a human will act. To state that the person is 'incapable' is a very strong statement and can only be made on a case-by-case basis - which by definition precludes a NERC standard.
Response:	
CenterPoint	Instead of establishing a new collection of competency measurements that are already defined by the NERC System Operator Certification Program and the NERC Continuing Education Program, PER-005 should align itself with these existing programs. The standard would have a greater benefit to the industry if it established the curriculum for these existing programs. PER-005 could provide the training topics necessary for advanced learning of reliability-related tasks. The NERC Continuing Education Program uses Individual Learning Activity applications to determine if the course meets its criteria. Such review of applications presently includes whether the SAT process was utlilized. This is another reason why PER-005 should form the curriculum to be used in the NERC Continuing Education Program. Then, the Continuing Education Program would review each course

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	application for compliance through the use of the NERC Continuing Education Review Panel. Per R1.1, specific tasks must be selected from the proposed generic task list (Attachment A) if the task is performed by the entity's system operator positions. The generic task list includes tasks that are NOT reliability-related. For example Item 22 states "monitor real-time market proces for accuracy." The generic task list should be reviewed and edited to include ONLY reliability-related tasks.
Response:	
NIPSCO	We need clarification in A.4.2 as to whom this standard is applicable and who will be the initially qualified personnel to sign off operators.
Response:	
NPCC RCS	R1.1 should refer to Transmission Operator instead of Transmission Owner. The proposed standard is not applicable to the Transmission Owner. Attachment B should have the same preamble as Attachment A.
Response:	
PG&E (1)	Paragraph 4.2 adds confusion to the standard. We recommend deleting this paragraph. The standard does not address requirements for delegates and it is therefore left to the reader to interpret what, if any, would be applicable. Delegates could be interpreted down to the crews, and we are sure that this interpretation is not intended.
Response:	
PG&E (2)	This standard, along with the approved NERC Continuing Education training, records would be duplicated by the continuing education provider, now that operators must maintain their certification through continuing education. The standard should be job task specific and not operator specific. Specific training requirements should be found in one standard, not throughout eighty or more.
Response:	
PJM	Several representatives of the ISO/RTO Council, in conjunction with discussions with Drafting Team members, have been informed that the intent of this Standard is to standardize and clarify what is and is not appropriate training materials for acceptance into the NERC Continuing Education Program. This is not well understood by the industry and, if this is indeed the case, PJM supports such an effort. The way the existing draft is being interpreted by the industry, however, is that this will be an additional requirement, over and above (and possibly in conflict with) the NERC Certification maintenance requirements currently contained in the NERC Continuing Education Program.

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	PJM agrees that: - Training is a critical function for our industry, and would note that NERC already ties Continuing Education Hours to the maintenance of NERC Certification. - General in-house training programs must be permitted to be structured to the varied ad hoc needs of the given organizations, their tools and their environment, and not subject to NERC standards. - Critical training be provided by accredited programs, and that NERC may desire to accredit programs used to provide CEH on those critical topics (e.g. Emergency Operations; Blackstart). - the result of a Training standard should be an operator that is prepared to handle that operators system; the result should NOT be the production and storage of paperwork. PJM does not agree that: - It is necessary that every organization has its own accredited program. As written, R1 requires that responsible entities complete the five phases of a systematic approach to training (SAT), which includes analysis, design, development, implementation, and evaluation) to establish a new or modify an existing training program. We do not agree that this should be a requirement. The requirement should be for the responsible entity receive training to help system operation personnel to acquire the competency to perform the applicable tasks pertaining to the RC, TOP and BA functions that the entity is responsible for or assigned. PJM neither endorses nor disapproves the SAT process as a good approach> However, how any training program is arrived at (i.e. what approach it takes) is not important and should not be a standard. If so inclined, NERC itself could offer an SAT-based Training program. How could one make an argument that using other approaches to arrive at a training program that (a) list the tasks and competency level required to perform the task, (b) include the minimum requirements stipulated in this standard such as the 32 hours emergency training, (c) has provision for a training schedule, review process, etc. is not an acceptable approach? Performance and capability are subjective ideas. Given all of the tests and training, no one can predict how a human will act. To state that the person is 'incapable' is a very strong statement and can only be made on a case-by-case basis - which by definition precludes a NERC standard.

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Response:	
RCSDT	The RCSDT has a conflict between teams for ownership of the scope for PER-004 and feel that it belongs with Project 2006-1 which has PER-004 posted with PER-005 for comment. Project 2006-1 removed three of the PER-004 requirements and left in two. During the RCSDT review, we removed the same three requirements but also suggested removing the other two because they are redundant with other standards as follows: PER-004 R.1 is redundant with PER-003 PER-004 R.5 is redundant with COM-001 and IRO-002 The RCSDT request that ownership of PER-004 be scoped within Project 2006-1. The RCSDT is willing to assist Project 2006-1 in completing the review task. Respectfully, William M. Hardy RCSDT - Chair
Response:	
SRP	The standard describes a specific “Systematic Approach to Training (SAT)”. This includes specific “phases” that must be included with various violation severity levels associated with the use/non use of these phases. The Standard as written is exceedingly restrictive in not allowing other training options to be considered for RC’s, BA’s and TO’s. An entity should have the option to select a training philosophy and program that meets their individual needs. This “one size fits all” for the entire industry is entirely too restrictive.
Response:	
SDG&E	Applicability 4.2 is unclear. Who do you define as delegates? Are you looking to expand the applicability to personnel that are outside the control center real time operating postions? Also it refers to applying to those that "impact reliability"? This should be for something that has a signficant negative impact, not just any impact, no matter how diminimus. There needs to be more clarity as to whom the System Operator training standards apply. Attachment A: Are you implying that anyone that does any of these function is in a System Operator position? In some cases, this work is done by back office staff or engineering. I do not believe all of these tasks need to be done by a System Operator with the level of training set up for them that you have designed. For example, Item 45, Perform next day reliability analysis of the electric system. This may be done by engineering staff, rather than a System Operator. Are you now saying they are

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	System Operators? Or are you still limiting System Operators to the real-time operating positions that control the system?
Response:	
We Energies	PER-002-0 R4 allows "five days per year of training and drills using realistic simulations of system emergencies". PER-005-1 R3.1 allows only "using drills, exercises, or simulations". Removal of the word "training" forces the 32 hours to be only drills, exercises, or simulations. Classroom type training could not be counted toward the 32 hours.
Response:	
Garland	As stated in question #9 above, small utilities do not have unlimited resources to budget only to training. This standard would place an undue burden on training departments to meet compliance criteria that would result in additional staff needed that small entities can not meet. R4 -How are we supposed verify the capabilities of the each real time operator? How will someone with a NERC certification that is not working a real time desk position, (i.e. training, other administrative rolls, switching coordinator) be assessed? How will operators be assessed annually under R2? Why would any entity want to add to the task list when you can not meet the requirements already stated? There are many items in the task list that are not currently done in ERCOT by Transmission and Generation Operators on a utility level, but rather done on the ERCOT regional level so how can one be assessed on that requirement. I would see that entities will be excluding task from the list rather than adding them. A systematic approach to training is the way to approach training needs, but this approach seems to be a bit to aggressive without consideration for the small utilities. NERC should take the lead in developing training programs that can be administered be regional entities that are appropriate for the region.
Response:	
HQT	R1.1 should refer to Transmission Operator instead of Transmission Owner. The proposed standard is not applicable to the Transmission Owner. Attachment B should have the same preamble as Attachment A.

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Response:	
IESO	The IESO appreciates the opportunity to comment, and commends the drafting team for responding positively to our comments on the previous draft standard and SAR. However, we have a major difficulty with this standard: 1. R1 require that responsible entities complete the five phases of a systematic approach to training (SAT), which includes analysis, design, development, implementation, and evaluation - ADDIE) to establish a new or modify an existing training program. We do not agree that this should be a requirement. The requirement should be for the responsible entity to develop an effective training program to help system operation personnel to acquire the competency to perform the applicable tasks pertaining to the RC, TOP and BA functions that the entity is responsible for or assigned. We neither endorse nor disagree that the SAT process is a good approach, but how the training program is arrived at (i.e. what approach it takes) is not important and should not be a standard. The 2003 Blackout report emphasized a need to train system operators to perform all tasks assigned to their positions. This can be met by requiring responsible entities to develop programs that cover training on all the tasks assigned to the operators, within the scope of the RC, TOP and BA functions, provide the resource for delivering the training. To achieve this, let us reiterate our previous suggestions: a. Developing a training program which lists the tasks (specifically for the RC, BA and TOP as listed in the Functional Model) to be performed and the competency level required to perform the tasks; b. Delivering the training program; c. Recording, tracking and assessing progress of the persons receiving training; d. Planning, providing resource, reviewing and adjusting (as necessary) the training program annually. (2) We realize that system operators may perform other tasks over and above those identified for the RC, BA and TOP functions. However, these other tasks are outside of the scope of the envisaged certification requirements and hence outside of the scope of this standard. The term "company-specific reliability related task" lends itself to interpretation that other reliability tasks (such as those performed by GOP, DP, etc.) must also be included in the training program. We suggest this term be revised, or more words be used to clearly stipulate that only the tasks assigned to the above 3

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	functions need to be included, depending on the structure and the registered function(s) of the organization.
Response:	
ISO New England	R1.1 should refer to Transmission Operator instead of Transmission Owner. The proposed standard is not applicable to the Transmission Owner. Attachment B should have the same preamble as Attachment A.
Response:	
Manitoba Hydro	I still have a concern with whether or not this would be fairly applied by all utilities. Most utilities will try and keep a minimum set of tasks and the assessment process will be treated inconsistently across the utilies.. This has been a better attempt at providing the miniimum tasks for each type of system operator but again, there will be no way the NERC or an audit team will be able to determine if the task should be there or not. Some way of tying the metrics being developed by the TADS might be away for determining training needs.
Response:	
MISO Stakeholders	The scope of the Certifying System Operators SAR indicates that they will determine who needs to be certified. Yet, this standard in section 4.2 of Applicability section specifies who should be certified. This should be coordinated with the CSO SDT. Requirement R1 in PER-004-2 will be redundant with standards created by the CSO SDT. We recommend eliminating it. Requirement 2 is also poorly defined and not measurable. How does one place particular attention on SOLs and IROLs? This a relative statement that leaves the requirement open to significant future challenges during enforcement. The standard appears to have only 4 requirements, yet is 27 pages long. It is too complex. All registered entities should have a training program. It does not have to be a SAT program.
Response:	
MRO	Please explain how the performance reset period of one month would work when the training program is being assessed annually per R2.
Response:	
SPP ORWG	While we don't have an issue with requiring a training program, we do take exception to having to maintain all the documentation that will be required as the standard is currently proposed.
Response:	
WECC OTS	The WECC OTS is the principle group in the Western Interconnection to support the WECC training program and providing support to the trainers in the West. It is the OTS belief that quality training

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	can and should result in quality System Operators and improved system reliability and therefore, we are supportive of the effort by the drafting team for their efforts to ensure the system operator responsible for the BES meets a minimum competency and knowledge levels. Quality training requires analysis and process and the OTS supports a requirement for development, delivery, and evaluation of system operator training using a "systematic approach to training" as required in this Standard and endorsed by the FERC. However, the OTS feels that this standard, along with the approved NERC Continuing Education training, records would be duplicated by the continuing education provider, now that operators must maintain their certification through continuing education. Therefore, the WECC OTS recommends this standard be job task specific and not operator specific. The OTS has also identified several training specific needs in other NERC Standards and would like to recommend that all training requirements in the current NERC Standards and future Standards only be identified in the NERC System Personnel Training Standard. While it is necessary to mention in the various standards, training needs per that standard, specific training requirements should be found in one standard, not amongst eighty or more. This allows the training staff responsible for the training compliance measures to coordinate and provide training for all future and current training needs. OTS suggests this Standard focus on Certified System Operators only at this time. The training for CE to support Certified System Operators using the SAT process should be covered at this time.
Response:	

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Standard drafting team appointed by the Standards Authorization Committee on June 21, 2006.
2. Standards Drafting Team posted draft standard for comment on September 27, 2006.
3. Standards Drafting Team responded to comments and posted the revised standard on August 15, 2007.

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed standard and its associated implementation plan for a 45-day comment period, from August 15, 2007 to October 1, 2007.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments and post a revised standard and implementation plan for a second comment period for 45-days.	August 15 – October 1, 2007
2. Respond to comments on the second draft of the proposed standard.	November 1, 2007
3. Obtain the Standards Committee's approval to move the standard forward to balloting.	November 15, 2007
4. Post the standard and implementation plan for a 30-day pre-ballot review.	December 1 – January 1, 2008
5. Conduct an initial ballot for ten days.	January 2 – January 11, 2008
6. Respond to comments submitted with the initial ballot.	February 15, 2008
7. Conduct a recirculation ballot for ten days.	February 15 – February 25, 2008
8. Post for a 30-day preview for board.	March 1-March 31, 2008
9. BOT adoption.	April 15, 2008

A. Introduction

1. Title: **System Personnel Training**

2. Number: PER-005-1

3. Purpose: To ensure that System Operators performing real-time, reliability-related tasks on the North American Bulk Electric System are competent to perform those reliability related tasks. The competency of System Operators is critical to the reliability of the North American Bulk Electric System.

4. Applicability:

4.1. Functional Entities:

4.1.1 Reliability Coordinator.

4.1.2 Balancing Authority.

4.1.3 Transmission Operator.

4.2. This standard applies to System Operator positions of the entities listed in 4.1 and their delegates who can directly, or through communications, impact reliability by producing a real-time response from the Bulk Electric System.

5. Proposed Effective Date for Regulatory Approvals:

5.1. Requirement 3 in the standard shall become effective on the first day of first quarter after applicable regulatory approval (or the Reliability Standards otherwise become effective on the first day of first quarter after Board of Trustee adoption in jurisdictions where regulatory approval is not required).

5.2. Requirement 2 in the standard shall become effective 18 months after the first day of the first quarter following regulatory approval (or the Reliability Standards otherwise become effective 18 months after the first day of the first quarter after Board of Trustee adoption in those jurisdictions where regulatory approval is not required).

5.3. Requirement 1 and Requirement 4 shall become effective 36 months after the first day of the first quarter following regulatory approval (or the Reliability Standards otherwise become effective 36 months after the first day of the first quarter after Board of Trustee adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall complete the five phases of a systematic approach to training (SAT) (which includes analysis, design, development, implementation, and evaluation) to establish a new or modify an existing training program(s) that addresses Bulk Electric System (BES) company-specific reliability-related tasks performed by its System Operators. [Risk Factor: Medium] [Time Horizon: Long-term Planning]

R1.1. To create a company-specific list of BES reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Owner shall select all tasks performed by its System Operator positions from the Generic Task List (provided in Attachment A) and add other BES reliability-related tasks performed by its System Operator positions.

R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall assess at least annually the training needs of each System Operator position to determine the mis-match between acceptable and actual performance capability. [Risk Factor: Medium] [Time Horizon: Long-term Planning]

R2.1. The assessment shall include identification of mis-matches between acceptable and actual performance capability that need to be addressed through future training.

R2.2. The assessment shall include identification of training required to perform new or revised tasks from the company-specific reliability related tasks.

R3. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each System Operator with at least 32 hours annually of emergency operations and system restoration training. [Risk Factor: Medium] [Time Horizon: Long-term Planning]

R3.1. The emergency operations and system restoration training shall include the principles and procedures needed for recognizing and responding to emergencies, using drills, exercises or simulations of system conditions in subject areas from the Emergency Operations Topics (provided in Attachment B).

R3.1.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall add or remove topics from the Emergency Operations Topics to reflect emergency operations and system restoration topics that apply to its organization.

R4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify the capabilities of each of its real-time System Operators to perform each assigned task on its list of company-specific BES reliability-related tasks. [Risk Factor: Medium] [Time Horizon: Long-term Planning]

C. Measures

M1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence of a SAT-developed BES System Operator training program with evidence of the following SAT-related outcomes:

M1.1. Analysis that results in a list of company-specific BES reliability-related tasks and measurable or observable criteria for desired performance for each task

M1.2. Design and development of training materials that result in learning objectives and content that is derived from results of training analysis

M1.3. Implementation of the training program, as identified in the training analysis

M1.4. Evaluations and assessments of training delivered to determine if learning objectives are met

M2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection the results of its latest assessment for each position, as specified in R2.

M3. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide evidence that each System Operator has obtained 32 hours of emergency operations or system restoration training, as specified in R3.

M4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection verification of the capabilities for each real-time System Operator, as specified in R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Enforcement Authority (CEA)

1.2. Compliance Monitoring Period and Reset

The performance reset period for all requirements is one month.

1.3. Data Retention

For all requirements and measures, each Reliability Coordinator, Balancing Authority and Transmission Operator shall retain evidence of compliance for four years or since its most recent on-site compliance audit, whichever is greater. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall retain all data used to show evidence it is following or followed any mitigation plan associated with this standard.

The Compliance Monitor shall retain data, including self-certifications, since its last on-site audit and all documentation from other compliance monitoring methods used since the last on-site compliance audit. The Compliance Monitor shall retain any data used in mitigation plans associated with this standard.

1.4. Additional Compliance Information

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall demonstrate compliance through self-certification submitted to its Compliance Enforcement Authority annually.

The Compliance Enforcement Authority shall conduct a scheduled on-site review once every three years, and may conduct spot checks and investigations to assess performance.

2. Violation Severity Levels

2.1. Lower: There shall be a lower violation for each subsection in which one or more of the following conditions exist:

2.1.1 None

2.1.2 None

2.1.3 The responsible entity did not add or remove topics from the Emergency Operations Topics that apply to their organization.

2.1.4 None

2.2. Moderate: There shall be a moderate violation for each subsection in which one or more of the following conditions exist:

2.2.1 The responsible entity has completed a list of company-specific reliability-related tasks from the Generic Task List (Provided in attachment A), and has started creating a list identifying all other reliability-related task that the company performs, but the list is not complete.

NOTE: If the entity violates R1.1, the entity is also in violation of R1, (failure to perform the Analysis phase of the SAT process).

2.2.2 The responsible entity has determined training required based on the mis-match between acceptable and actual performance capability but has not included the training identified in its current schedule.

2.2.3 The responsible entity provided at least 32 hours of training on emergency operations or system restoration, annually, but did not include training in subject areas listed in Attachment B.

2.2.4 **None**

2.3. **High: There shall be a high violation for each subsection in which one or more of the following conditions exist:** The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements.

2.3.1 The responsible entity has a system operator training program for all its system operator positions (identified in Section 4.2) but the entity did not use or provide evidence of use of one of the five phases of a SAT process listed below when establishing new system operator training: (R1)

- Analysis that results in a list of company-specific reliability-related tasks and measurable or observable criteria for desired performance for each task
- Design that results in learning objectives
- Develop training content that is derived from results of training analysis and learning objectives.
- Implementation of the training program, as identified in the training analysis
- Evaluations and assessments of training delivered to determine if learning objectives are met

OR

The responsible entity has a system operator training program for all its system operator positions (identified in Section 4.2) but the entity did not use or provide evidence of use of one of the five phases of a SAT process listed below when making modifications to an existing system operator training program:

- Analysis that results in a list of company-specific reliability-related tasks and measurable or observable criteria for desired performance for each task
- Design that results in learning objectives
- Develop training content that is derived from results of training analysis and learning objectives.
- Implementation of the training program, as identified in the training analysis
- Evaluations and assessments of training delivered to determine if learning objectives are met

OR

The responsible entity does not have a system operator training program based on the SAT process for one of its system operator positions (as identified in Section 4.2).

2.3.1.1 The responsible entity has started creating a list or has a partial list identifying its company specific list of reliability related tasks from the generic task list (in Attachment A), but the list is not complete

NOTE: If the entity violates R1.2, the entity is also in violation of R1, (failure to perform the implementation phase of the SAT process).

2.3.2 The responsible entity has not performed an assessment which includes identification of measurable or observable criteria for desired performance to each task for the determination of the training needs for one of its system operating position.

2.3.2.1 The responsible entity has not identified training required based on the mis-match between acceptable and actual performance capability.

2.3.3 The responsible entity provided to its system operators at least, 32 hours of emergency operations or system restoration training, annually, but not all its System Operators has completed or evidence shows will not have completed the required annual training.

2.3.3.1 The responsible entity provided at least 32 hours of training on emergency operations or system restoration, but the training did not include training in principles and procedures needed for effectively recognizing and responding to emergencies **OR**

The emergency operations or system restoration training delivery method did not include drills, exercises, or simulations of system conditions,

2.3.4 The responsible entity has performed an assessment of its System Operator's capabilities to perform each identified task that is on its company-specific reliability-related task, but not for each of its System Operators.

2.4. Severe: There shall be a severe violation for each subsection in which one or more of the following conditions exist. The responsible entity has failed to meet the reliability objective of the requirement.

2.4.1 The responsible entity has a system operator training program for all its system operator positions (identified in Section 4.2) but the entity did not use or provide evidence of use of two of the five phases of a SAT process listed below when establishing new system operator training:

- Analysis that results in a list of company-specific reliability-related tasks and measurable or observable criteria for desired performance for each task
- Design that results in learning objectives
- Develop training content that is derived from results of training analysis and learning objectives.
- Implementation of the training program, as identified in the training analysis
- Evaluations and assessments of training delivered to determine if learning objectives are met

OR

The responsible entity has a system operator training program for all its system operator positions (identified in Section 4.2) but the entity did not use or provide evidence of use of two of the five phases of a SAT processes listed below when making modifications to an existing system operator training program. :

- Analysis that results in a list of company-specific reliability-related tasks and measurable or observable criteria for desired performance for each task
- Design that results in learning objectives

- Develop training content that is derived from results of training analysis and learning objectives.
- Implementation of the training program, as identified in the training analysis
- Evaluations and assessments of training delivered to determine if learning objectives are met

OR

The responsible entity does not have a SAT program for its system operators.

2.4.1.1 The responsible entity failed to create a company specific list of reliability related tasks from the generic task list. (in attachment A) **OR**

The responsible entity failed to create a list of all other reliability-related task the company performs.

2.4.2 The responsible entity has not performed an assessment which includes identification of measurable or observable criteria for desired performance to each task for the determination of the training needs for two of its system operating position **OR**

The responsible entity has not performed an annual assessment as required by R2.

2.4.3 The responsible entity did not provide to its system operators at least 32 hours of emergency operations or system restoration training **OR**

The responsible entity has provided 32 hours of emergency operations and system restoration training but the training has not provided annually.

2.4.4 The responsible entity has not performed an assessment on its System Operator's capabilities to perform each identified task that is on its company-specific reliability-related task list

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking

Attachment A: Generic Task List

Attachment A presents a generic list of tasks to assist with the creation of a company-specific list of reliability-related tasks. Entities shall add or remove from the list to create a list of reliability-related tasks applicable to their organization.

General Control Center Operations Tasks:

ITEM#	TYPE OF ACTIVITY	GENERAL CONTROL CENTER OPERATIONS TASKS
1	Communication	Provide real-time system information to the Reliability Coordinator.
2	Communication	Coordinate reliability processes and actions with and among other Reliability Coordinators.
3	Communication	Issue reliability alerts to Generator Operators, Load-Serving Entities, Transmission Operators, Transmission Service Providers, Balancing Authorities, Regional Councils, and NERC
4	Communication	Produce and publish system status information (e.g., OASIS, IRN, and RCIS)
5	Communication	Prepare and provide data to reliability coordinator for later inclusion in NERC reports
6	Communication	Ensure all balancing authorities or transmission operators are aware of solar magnetic disturbances (SMD) forecast information
7	Communication	Communicate the status of system conditions with appropriate reliability coordination offices
8	Communication	Communicate the status of system conditions with appropriate balancing authorities and/or transmission operators
9	Communication	Report disturbances to NERC following the guidelines within the U.S. Department of Energy's most recent Power System Emergency Reporting Procedures
10	Communication	Communicate with interconnected systems during normal and emergency conditions using established procedures
11	Communication	Coordinate operations between the host balancing authority or transmission operator and any transmission operating entities that exist within the host balancing authority and/or transmission operator's boundaries to ensure transmission reliability
12	Communication	Report to the regional council staff within 24 hours after a disturbance affecting your system has occurred
13	Communication	Report any disturbances or unusual occurrences, suspected or determined to be caused by sabotage to the appropriate systems, governmental agencies, and regulatory bodies
14	Communication	Coordinate reliability processes and actions with and among other reliability coordinators

ITEM#	TYPE OF ACTIVITY	GENERAL CONTROL CENTER OPERATIONS TASKS
15	Communication	Utilize the voice and data telecommunication systems as required while adhering to Interconnection and regional operating procedures
16	Monitor	Monitor real-time operational information from balancing authorities and transmission operators.
17	Monitor	Interpret SCADA-generated alarms and information, and then take appropriate actions to maintain system reliability
18	Monitor	Check data and verify accuracy of each metering point used by Supervisory Control and Data Acquisition (SCADA)
19	Monitor	Monitor performance of power system equipment and call out system personnel when appropriate
20	Monitor	Monitor system load and generation
21	Monitor	Ensure all special protection systems and special design features are in service as needed
22	Monitor	Monitor real-time market prices for accuracy
23	Monitor	Monitor and respond to alarms from status of special protective schemes
24	Monitor	Verify data used in operation
25	Monitor	Monitor the RCIS and respond to any information provided
26	Monitor	Monitor all reliability-related system parameters, such as MW, MVAR, voltage, and amps to determine system conditions
27	Monitor	Monitor and control access to the control center to prevent sabotage
28	Monitor	Monitor all reliability-related data within a reliability coordinator area
29	Monitor	Monitor and periodically test normal and emergency telecommunication systems that link with interconnected systems to ensure communications are adequate and continuous
30	Monitor	Monitor and respond to telecommunication alarms or failures and notify the appropriate personnel
31	Monitor	Monitor and maintain defined voltage profiles to ensure system reliability
32	Monitor	Monitor and validate telemetry data for accuracy
33	Monitor	Monitor control center systems and support equipment and call out appropriate assistance as needed
34	Operating	Analyze operations log, and oral information from system operator leaving shift
35	Operating	Maintain records of special protection system, special design feature, and transmission protection system mis-operations
36	Operating	Evaluate impact of current weather conditions on system operations

ITEM#	TYPE OF ACTIVITY	GENERAL CONTROL CENTER OPERATIONS TASKS
37	Operating	Evaluate system conditions and apply operating guides when applicable
38	Operating	Evaluate the extent of an outage or disturbance and develop a plan of restoration
39	Operating	Identify operating problems and deficiencies, and recommend corrective measures
40	Operating	Respond to performance survey requests
41	Operating	Provide input to ensure that the operations computer database is up to date
42	Operating	Prepare daily reports and logs generated to meet company and regulatory requirements
43	Operating	Adjust control systems to compensate for any equipment errors or failures
44	Operating	Perform same-day reliability analysis of the electric system
45	Operating	Perform next-day reliability analysis of the electric system
46	Operating	Analyze and authorize requests for equipment outages
47	Operating	Enforce operational reliability requirements
48	Operating	Compile regional system data reports
49	Operating	Operate primary and backup telecommunications systems as required
50	Operating	Schedule system telecommunications, telemetering, protection, and control equipment outages to ensure system reliability
51	Operating	Maintain current knowledge of power system modifications and additions
52	Operating	Ensure that every effort is made to remain connected to the Interconnection
53	Operating	Take action as necessary to protect the system if it becomes endangered by remaining interconnected
54	Operating	Apply guidelines, including lists of utility contact personnel, for reporting disturbances due to sabotage events
55	Operating	Direct to the appropriate entities those options necessary to relieve reliability threats and violations in a reliability coordinator area
56	Operating	Ensure the accuracy of current system status by updating necessary operating procedures, diagrams, and map board
57	Operating	Provide input to system planners to help maintain accuracy in system models used for reliability assessments
58	Operating	Evaluate, test, and/or confirm the accuracy of reliability assessment tools
59	Operating	Utilize interconnected operation services as needed to maintain system reliability

ITEM#	TYPE OF ACTIVITY	GENERAL CONTROL CENTER OPERATIONS TASKS
60	Operating	Utilize reactive resources from transmission and generator owners to maintain acceptable voltage profiles
61	Operating	Enforce compliance of operating reliability limits
62	Operating	Arm or verify that special protection systems are armed to meet system conditions (contingencies) as needed
63	Operating	Test, evaluate, and operate backup control center facilities/systems as needed
64	Operating	Implement procedures for the recognition of sabotage events on your facilities and multi-site sabotage affecting larger portions of the Interconnection
65	Operating	Implement specified procedural actions in the event of a FERC Standards of Conduct violation
66	Procedure	Complies with reliability requirements specified by Reliability Coordinator.
67	Procedure	Evaluate current operating practices and make recommendations for improvement to meet NERC reliability standards' requirements
68	Procedure	Implement system restoration procedures
69	Procedure	Maintain a working knowledge of regional, NERC, FERC, and company specific guides, policies, and standards

Transmission Tasks:

ITEM#	TYPE OF ACTIVITY	TRANSMISSION TASKS
1	Limits	Monitor and operate or direct the operations of the transmission system within equipment and facility ratings.
2	Operating	Notify Generator Operators of transmission system problems in compliance with NERC requirements.
3	Outage	Adjust transmission configuration to implement proposed transmission system outage plan
4	Outage	Build contingency case for scheduled outages for next day
5	Outage	Coordinate planned and unplanned transmission outages with all impacted systems to ensure transmission system reliability
6	Outage	Direct transmission operators to revise maintenance plans as required, and as permitted by agreements
7	Outage	Implement transmission outages to ensure system reliability
8	Outage	Initiate the cancellation of scheduled transmission work when system conditions require
9	Outage	Interpret relay targets, oscillograph readings, breaker operations, and field observations to determine proper restoration methods during forced outages
10	Outage	Notify others of any planned transmission changes that may impact the operation of their facilities
11	Outage	Perform reliability analysis to determine impact of both scheduled and forced transmission outages
12	Outage	Receive and review transmission maintenance plans from transmission operators for reliability assessment
13	Outage	Report transmission outages to the reliability coordinators and other affected utilities
14	Limits	Coordinate with impacted systems, and monitor actual and/or expected operating reliability limit violations and respond as required
15	Limits	Develop or calculate system operating limits
16	Limits	Direct transmission operators to take actions to mitigate interconnection reliability operating limits
17	Limits	Ensure all tie-line limits are not exceeded
18	Limits	Ensure that transmission contract paths are not exceeded
19	Limits	Identify, communicate, and direct actions to relieve reliability threats and limit violations in the reliability coordinator area
20	Limits	Initiate control actions resulting from thermal limit violations, considering the responsiveness of the system
21	Limits	Monitor and respond to transmission system equipment rating violations
22	Limits	Monitor bulk transmission elements to determine constraints and operating limit violations
23	Limits	Monitor major transmission lines, flow gates, and scheduling paths

ITEM#	TYPE OF ACTIVITY	TRANSMISSION TASKS
24	Limits	Coordinate with transmission operators and transmission service providers on real-time transmission system limitations.
25	Limits	Monitor interconnection reliability operating limits .
26	Limits	Recalculate interconnection reliability operating limits based on current or future conditions, and according to transmission and generator owners' specified equipment ratings
27	Limits	Develop interconnected operating reliability limits
28	Operating	Analyze/research any bulk system disturbances affecting your system
29	Operating	Respond to disturbance conditions
30	Operating	Monitor and operate transmission system within its designed capabilities
31	Operating	Monitor radio system for calls requiring response
32	Operating	Monitor system frequency and initiate a hotline conference call when frequency error exceeds specified limits
33	Operating	Monitor the condition of the transmission system and respond as required (including shedding firm load) to avoid voltage collapse and/or Interconnection separation
34	Operating	Monitor the voltages, and coordinate the reactive dispatch of transmission facilities, and the interconnections with neighboring systems
35	Operating	Develop special operating procedures to allow continued operation of the transmission system based on the results of a reliability analysis
36	Operating	Direct and/or control all energization and/or modification of new or existing facilities
37	Operating	Direct and/or control phase shifting transformer taps
38	Operating	Direct and/or control transmission switching
39	Operating	Direct and/or regulate the operation of the transmission system
40	Operating	Ensure adequate transmission facilities are available to meet external and internal requirements (real-time or hourly)
41	Operating	Implement corrective actions from transmission problems resulting from an underlying sub-transmission or distribution event (local reliability issues)
42	Operating	Maintain constant awareness of neighboring transmission system conditions
43	Operating	Maintain safe operating conditions for all persons and property within the transmission system
44	Operating	Operate control equipment to continuously and accurately meet its system and Interconnection control obligation and measure its performance
45	Operating	Perform reliability analysis (actual and contingency) for the reliability coordinator area
46	Operating	Provide oversight of transmission operational plans, direct revisions as required, and as permitted by agreements
47	Operating	Respond to solar magnetic disturbance (SMD) warnings as required by system

ITEM#	TYPE OF ACTIVITY	TRANSMISSION TASKS
		operating procedures
48	Operating	Specify interconnected operation services requirements for transmission reliability (e.g., reactive requirements, location of operating reserves)
49	Operating	Supervise and coordinate all activity at switching stations, generating stations, and transmission switchyards
50	Operating	Utilize load flow modeling tools to determine power flow changes and optimum system configurations during normal and emergency conditions
51	Voltage	Deploy reactive resources to maintain acceptable voltage profiles.
52	Voltage	Coordinate voltage reduction as requested by the balancing authority or as directed by the reliability coordinator.
53	Voltage	Direct voltage reduction
54	Voltage	Approve system voltage regulating equipment outages to ensure adequate system voltage and system reliability is maintained
55	Voltage	Coordinate operation of voltage control equipment with interconnected utilities
56	Voltage	Direct transmission operators to reduce voltage or shed load if needed to ensure balance in real-time
57	Voltage	Identify and respond to conditions likely to lead to voltage collapse
58	Voltage	Implement voltage reductions as directed by a transmission operator
59	Voltage	Minimize system voltage decay and prevent cascading outages
60	Voltage	Schedule system voltage regulating equipment outages to ensure adequate system voltage and system reliability is maintained
61	Voltage	Utilize HVDC systems' reactive power control capabilities as a voltage control tool when appropriate
62	Voltage	Utilize transmission line removal as a voltage control tool only if system studies indicate that system reliability will not be degraded below acceptable levels
63	Limits	Request reliability coordinator to mitigate equipment overloads.
64	Congestion	Identify special operating procedures that may be necessary to maintain acceptable transmission loading
65	Congestion	Initiate line loading relief procedures upon request of members of the Interconnection using appropriate priority levels
66	Congestion	Initiate transmission loading relief procedures to relieve potential or actual loading on a constrained facility
67	Congestion	Manage transmission loading by directing the redispatch of generators or reconfiguring the transmission system to mitigate impact, including the load curtailment process
68	Congestion	Notify all affected areas that line loading relief has been requested, and that corrective actions are required
69	Congestion	Request the reliability coordinator to mitigate equipment overloads
70	Congestion	Run day-ahead congestion management market

ITEM#	TYPE OF ACTIVITY	TRANSMISSION TASKS
71	Congestion	Run hour-ahead congestion management market to allocate available transmission capacities
72	Congestion	Use the results from an available transfer capability (ATC) calculator to determine the impact of an interchange transaction on the transmission system
73	Congestion	Utilize the Interchange Distribution Calculator to determine transaction curtailments for transmission load relief
74	Congestion	Calculate and post changes in available transmission capacity
75	Congestion	Implement terms of interruption for transmission services according to contractual provisions
76		Direct load shedding
77	Load	Coordinate load shedding as requested by the balancing authority or as directed by the reliability coordinator.
78	Load	Issue corrective actions (e.g., curtailments or load shedding) to transmission operators, transmission service providers
79	Load	Adjust both short-term and future forecasts using actual load data and correction factors
80	Load	Call for interruptible loads to be shed when required
81	Load	Collect individual load profiles and forecasts of end-users energy requirements, and develop overall load profiles
82	Load	Compile load forecasts from load-serving entities within a balancing area
83	Load	Coordinate load shedding, and load restoration with, or as directed by the reliability coordinator
84	Load	Coordinate or direct use of controllable loads that have been bid as interconnected operations services
85	Load	Develop both short-term and future forecasts using actual load data and correction factors
86	Load	Monitor an area’s estimated and actual loads
87	Load	Respond to light load conditions

Generation Tasks:

ITEM#	TYPE OF ACTIVITY	GENERATION TASKS
1	Balancing	Direct resources (generator operators and load-serving entities) to take action to ensure balance in real time
2	Balancing	Ensure adequate generation capacity is available to meet external and internal requirements (real-time, or hourly)
3	Balancing	Respond to manual time error correction requests by regional time error monitor
4	Balancing	Allocate generation resources to meet system requirements
5	Balancing	Allocate load resources to meet system requirements
6	Balancing	Monitor AGC to ensure compliance with NERC CPS1 and CPS2 standards
7	Balancing	Perform system configuration evaluation for dispatching of imbalance energy based on real-time conditions
8	Balancing	Minimize inadvertent flows, losses, and CPS1 and CPS2 criteria violations
9	Balancing	Monitor AGC performance to diagnose and identify telemetry problems
10	Balancing	Compare actual generator output with anticipated schedules, and take action to account for the difference
11	Balancing	Dispatch generation resources economically while maintaining system reliability
12	Balancing	Monitor time error and initiate corrections
13	Balancing	Manually calculate ACE as necessary
14	Balancing	Publish next-day market results
15	Balancing	Monitor ramping capability for requested interchange schedules
16	Balancing	Ensure that the balancing authority is satisfying its Interconnection frequency regulation obligation
17	Balancing	Ensure that the balancing authority's frequency bias value is continually set at the proper value
18	Balancing	Monitor ACE to determine if the calculation is correct
19	Balancing	Inform the appropriate balancing authority of the status of its overlap regulation service
20	Balancing	Verify that the regulating capacity is distributed equitably over as many units as possible
21	Balancing	Manage generation biasing to avoid reliability limit violations
22	Balancing	Monitor response of units to the AGC signals
23	Balancing	Operate the AGC system in tie-line bias control mode unless such operation is adverse to system or Interconnection reliability
24	Balancing	Obtain replacement energy upon a loss of any major generating or interchange resource
25	Balancing	Respond to generation losses, recognizing reliability restrictions to effectively maintain tie-line flows
26	Balancing	Apply the principles of economic dispatch to generating units

ITEM#	TYPE OF ACTIVITY	GENERATION TASKS
27	Balancing	Respond to generation losses, recognizing economic and reliability restrictions
28	Balancing	Publish hour-ahead market results
29	Balancing	Publish day-ahead market results
30	Balancing	Declare an Energy Emergency Alert (EEA) when generation resources and reserves are inadequate to meet demand
31	Balancing	Consult with other impacted balancing authorities, adjust the AGC algorithm for the proper time periods (on-peak and off-peak) to account for known tie-line metering errors
32	Balancing	Review generation commitments, dispatch, and load forecasts
33	Balancing	Receive and review generation operations plans and commitments from balancing authorities for reliability assessment
34	Balancing	Control or direct generation biasing to provide overlap regulation service to other balancing authorities in accordance with contractual obligations
35	Balancing	Ensure adequate energy resources are available to meet external and internal requirements (real-time or hourly)
36	Congestion	Direct the reduction or shedding of load if needed to ensure balance within its balancing authority area.
37	Congestion	Direct generator operators to implement redispatch for congestion management.
38	Congestion	Issue corrective actions (e.g., curtailments or load shedding) to balancing authorities.
39	Congestion	Procure alternate sources of energy when reliability coordinator curtails transactions or calls for generation re-dispatch
40	Congestion	Issue generation dispatch adjustments to mitigate transmission congestion
41	Congestion	Direct balancing authorities to take actions to mitigate interconnection reliability operating limits
42	Congestion	Control, direct, or manage generation dispatch to avoid transmission reliability limit violations
43	Operating	Monitor output of units ensuring that MW output is within operating limits
44	Operating	Monitor output of units ensuring that MVAr output is within operating limits
45	Operating	Operate generation to minimize inadvertent power flow
46	Operating	Operate the SCADA and analog systems to control generation and monitor telemetered information
47	Operating	Select proper mode of automatic generation control for system conditions
48	Operating	Suspend automatic generation control as required
49	Operating	Monitor system fuel reserves
50	Operating	Communicate with generating station regarding work for anticipated increases or decreases that may cause limit changes
51	Operating	Monitor generation production data for correctness and ensure that records are developed and maintained as required

ITEM#	TYPE OF ACTIVITY	GENERATION TASKS
52	Operating	Monitor output of units ensuring that MW output is operating according to schedules
53	Operating	Monitor output of units ensuring that MVAr output is operating according to schedules
54	Operating	Supervise and coordinate all activity at generating stations
55	Operating	Monitor hydro generation and pond levels
56	Operating	Monitor generating unit governors to verify their operational status
57	Operating	Initiate manual control of generation, and maintain scheduled interchange following an AGC system component failure
58	Operating	Operate power facilities in compliance with environmental standards (e.g., air quality, wildlife)
59	Operating	Ensure that the AGC and other vital control performance equipment are functioning properly when using the backup power supply following the loss of the primary power supply
60	Operating	Verify the accuracy of the AGC tie-line metering by comparing hourly MWh meter totals to the totals derived from tie-line meter registers
61	Operating	Monitor the status and availability of generator voltage regulators and/or power system stabilizers, and respond as required to deficiencies that may impact system reliability
62	Operating	Test/verify the reactive capability of generating units
63	Operating	Administer generator start-up and shutdown schedules
64	Operating	Report the status of generator automatic voltage regulators and/or power system stabilizers to transmission operators
65	Operating	Provide oversight of generation operational plans, direct revisions as required, and as permitted by agreements
66	Operating	Validate adequacy of resource plans (in near real time)
67	Operating	Procure interconnected operations services from generator owners to ensure voltage support from generating resources is adequate
68	Operating	Notify generator operators of voltage limitations, or equipment overloads that may impact, or are impacting generator operations
69	Outage	Inform the reliability coordinator and impacted balancing authorities of interchange schedule interruptions due to generation or load interruptions within its balancing authority area.
70	Outage	Plan next-day generation required to implement a proposed outage
71	Outage	Implement terms of interruption for generation services according to contractual provisions
72	Outage	Implement or delay generation outages to ensure system reliability
73	Outage	Coordinate ramp down of unit going on planned outage
74	Outage	Adjust generation levels to implement proposed transmission system outage plan
75	Outage	Perform reliability analysis to determine impact of both scheduled and forced

ITEM#	TYPE OF ACTIVITY	GENERATION TASKS
		generation outages
76	Outage	Separate or shut down generators that are unsafe to operate during or after an area disturbance
77	Outage	Direct generation operators to revise maintenance plans as required, and as permitted by agreements
78	Reserves	Apply operating reserves when needed
79	Reserves	Respond to reserve sharing group requests for emergencies
80	Reserves	Perform day-ahead ancillary services auction
81	Reserves	Produce list of resources to meet additional energy requirements (from ancillary service market) to purchase in real time
82	Reserves	Monitor and analyze regional reactive reserve availability
83	Reserves	Perform instantaneous reserve checks
84	Reserves	Dispatch operating reserves to alleviate system emergency conditions
85	Reserves	Perform hour-ahead ancillary services auction
86	Reserves	Monitor and analyze regional operating reserves availability
87	Reserves	Reestablish required operating reserve levels as soon as possible following a contingency that results in operating reserve usage
88	Reserves	Administer performance tests for generating resources providing ancillary services (e.g., spinning, regulation, unit ramp rates)
89	Reserves	Determine required quantities of ancillary services
90	Reserves	Determine reserves needed for the next hour
91	Reserves	Determine reserves needed for the next day
92	Reserves	Determine reserves needed for future days (long term)
93	Reserves	Monitor reactive reserve levels to ensure adequate reactive reserves exist and are properly located to provide for adequate voltage levels under normal and emergency conditions
94	Reserves	Restore reactive reserves to acceptable levels as soon as possible after use
95	Reserves	Ensure adequate spinning and operating reserves are on line
96	Reserves	Ensure adequate spinning and/or operating reserves are dispersed throughout the system
97	Reserves	Monitor available operating reserves and take corrective actions to correct deficiencies

Interchange Tasks:

ITEM#	TYPE OF ACTIVITY	INTERCHANGE TASKS
1	Communication	Communicate with real-time scheduler regarding the purchase of resources
2	Communication	Notify source balancing authority and transmission service providers, or transmission operators when an interchange transaction must be modified or terminated
3	Communication	Notify intermediate balancing authorities when an interchange transaction must be modified or terminated
4	Communication	Notify participants of transaction curtailments or adjustments observing NERC communication protocols
5	Communication	Notify sink balancing authority or transmission service provider when an interchange transaction needs to be modified or terminated
6	Communication	Notify the interchange authority when interchange transactions are cancelled or terminated
7	Congestion	Curtail, terminate, or modify interchange transaction requests that aggravate operating limits
8	Congestion	Curtail transactions as directed across interfaces
9	Congestion	Ensure that the maximum net scheduled interchange with other balancing authorities does not exceed the available transfer capability
10	Congestion	Ensure that all curtailments are properly applied per reliability coordinators instructions
11	Congestion	Analyze the impact of proposed requests for transmission service and interchange schedules on the bulk power system
12	Congestion	Reestablish curtailed interchange transactions with affected balancing authorities or transmission operators
13	Congestion	Coordinate reallocation and reloading of interchange transactions during transmission loading relief procedures
14	Monitor	Monitor status of NERC interchange transaction tags to ensure timely approval and implementation
15	Operating	Arrange transactions for energy to serve projected demand
16	Operating	Determine proper use of dynamic schedules of remote generating units as to their contribution to operating reserves
17	Operating	Manually calculate net interchange when needed
18	Operating	Determine energy excess after meeting load, reserves, and contract obligations
19	Operating	Verify the accuracy of time error monitoring equipment
20	Operating	Maintain the confidentiality of interchange transactions
21	Operating	Protect the confidentiality of all interchange transaction information
22	Operating	Check inadvertent interchange accounts with other balancing authorities at the end of each day

ITEM#	TYPE OF ACTIVITY	INTERCHANGE TASKS
23	Operating	Ensure that all appropriate transmission rights are assigned to all energy schedules (e.g., OASIS reservations) prior to their implementation
24	Operating	Agree upon daily schedule totals and energy imbalance totals with balancing authorities or transmission operators and other schedulers as needed
25	Operating	Assess, approve, or deny interchange transaction requests based on reliability analysis from the ATC calculator
26	Operating	Create NERC interchange transaction tag with all required information
27	Operating	Implement or terminate interchange transactions when needed
28	Operating	Adjust interchange transactions
29	Operating	Monitor the electronic (interchange) tagging system for accuracy of information (e-tagging)
30	Operating	Ensure all import and export schedule totals are checked for accuracy and correctness with each utility at the end of the day
31	Operating	Ensure interchange transactions are conducted in accordance with regional and NERC standards
32	Operating	Implement inadvertent interchange payback schedules with other entities
33	Operating	Submit a request to obtain the necessary transmission reservations to implement transactions
34	Operating	Manually calculate ACE as necessary
35	Operating	Adjust transfers across interfaces to maintain system reliability
36	Operating	Submit NERC interchange transaction tag to transmission providers and balancing authority or transmission operators on the scheduling path within proper timeframe
37	Operating	Secure appropriate transmission rights in response to system emergencies
38	Operating	Enter interchange transactions into the control area's scheduled interchange
39	Operating	Coordinate with any controlled interface operators (e.g., DC ties) that are part of an interchange transaction-scheduling path
40	Operating	Participate in system planning studies to determine transfer capabilities and operating limits
41	Operating	Check and validate hourly tie-line data
42	Operating	Monitor inadvertent accumulations in both the on-peak and off-peak accounts
43	Operating	Maintain knowledge of existing and proposed Interconnection agreements and contracts
44	Operating	Maintain accurate settlement records for bulk power sales and purchases
45	Operating	Apply tariffs associated with rates and services uniformly to all parties
46	Operating	Evaluate and respond to customer requests for transmission and ancillary services via the OASIS
47	Operating	Ensure that the ramp rate, start and end times, energy profile, and losses are communicated to all parties in the transaction

ITEM#	TYPE OF ACTIVITY	INTERCHANGE TASKS
48	Operating	Identify potential parallel flow impacts on pending interchange
49	Operating	Approve interchange transactions based upon a reliability perspective
50	Operating	Monitor dynamic energy schedules for the appropriate use of transmission rights
51	Operating	Administer interchange scheduling and recordkeeping requirements with interconnected balancing authorities or transmission operators or other utilities
52	Operating	Implement interchange schedules
53	Operating	Approve or deny bilateral schedules from the reliability perspective
54	Operating	Confirm and approve interchange transactions from ramping ability perspective
55	Operating	Enter interchange transaction information into reliability assessment tools
56	Operating	Determine and post available transfer capability values
57	Operating	Secure energy and transmission services to serve end-use customers
58	Operating	Perform after-the-hour checkout of actual and scheduled interchange with adjacent balancing authorities
59	Operating	Approve or deny transmission service requests in accordance with any tariff requirements (OASIS)
60	Operating	Ensure transmission reliability margins, total transfer capabilities and available transfer capabilities are correctly posted

Emergency Operations Tasks:

ITEM#	TYPE OF ACTIVITY	EMERGENCY OPERATIONS TASKS
1	Capacity	Request emergency energy upon loss of a resource
2	Capacity	Respond to capacity deficiency
3	Capacity	Respond to loss of energy resources within allowable regional or pool timeframe
4	Capacity	Prepare for a capacity emergency by bringing on all available generation
5	Capacity	Prepare for a capacity emergency by postponing equipment maintenance
6	Capacity	Prepare for a capacity emergency by scheduling emergency energy purchases
7	Capacity	Prepare for a capacity emergency by reducing load
8	Capacity	Prepare for a capacity emergency by initiating voltage reductions
9	Capacity	Prepare for a capacity emergency by requesting emergency assistance from other systems
10	Capacity	Schedule available emergency assistance with as much advance notice as possible given a capacity emergency
11	Capacity	Utilize the assistance provided by the Interconnection's frequency bias (in a capacity emergency) only for the time period necessary to utilize operating reserves
12	Capacity	Utilize the assistance provided by the Interconnection's frequency bias (in a capacity emergency) only for the time period necessary to analyze ability to recover using own resources
13	Capacity	Utilize the assistance provided by the Interconnection's frequency bias (in a capacity emergency) only for the time period necessary to schedule emergency assistance from others
14	Freq	Direct corrective actions to correct abnormal frequency
15	Load Shed	Manually shed load to alleviate system emergency conditions
16	Load Shed	Following the activation of automatic load shedding schemes, restore system load as appropriate for current system conditions and in coordination with adjacent systems
17	Load Shed	Following the activation of automatic load shedding schemes, shed additional load manually if there is insufficient generation to support the connected load
18	Load Shed	Following the activation of automatic load shedding schemes, monitor system voltage levels to ensure high voltage conditions do not develop
19	Load Shed	Following the activation of automatic load shedding schemes, monitor system frequency to ensure high frequency conditions do not develop
20	Load Shed	Following the activation of automatic load shedding schemes, monitor the performance of any automatic load restoration relays
21	Load Shed	Following the activation of automatic load shedding schemes, resynchronize transmission at preplanned locations if possible
22	Load Shed	Following the activation of automatic load shedding schemes, disable automatic underfrequency relays if system conditions warrant
23	Load Shed	Direct distribution providers to shed load when required for system reliability

ITEM#	TYPE OF ACTIVITY	EMERGENCY OPERATIONS TASKS
24	Load Shed	Use manual load shedding to prevent imminent separation from the Interconnection due to transmission overloads or to prevent voltage collapse
25	Procedure	Implement emergency procedures.
26	Procedure	Notify the reliability coordinator of the implementation of its own emergency procedures.
27	Procedure	Comply with reliability coordinators' instructions during emergency conditions
28	Procedure	Direct implementation of emergency procedures
29	Procedure	Maintain knowledge of existing and proposed emergency assistance agreements and contracts
30	Procedure	Mandate the sale or purchase of energy to optimize reliability
31	Procedure	Respond to system emergencies and frequency deviations to meet local, regional, and NERC DCS requirements
32	Procedure	Notify appropriate personnel or departments in event of an emergency
33	Procedure	Perform or direct actions such as starting generation, canceling pre-scheduled maintenance, schedule interchange, or shed load to return the system to a secure state
34	Procedure	Perform regular testing of emergency procedures to determine preparedness and alertness of shift personnel
35	Procedure	Provide emergency services coordination for field personnel
36	Procedure	Respond to generation losses, recognizing economic and reliability restrictions to effectively maintain tie-line flows
37	Procedure	Respond to requests for emergency assistance from neighboring systems
38	Procedure	Declare system emergencies
39	Procedure	Develop and/or implement contingency plans when facilities/equipment are forced out of service
40	Procedure	Formulate a plan to implement corrective actions when equipment ratings are exceeded or anticipated to be exceeded
41	Procedure	Use sub-regional, regional, and NERC hotline to coordinate actions during emergency conditions
42	Procedure	Schedule emergency energy when needed and create interchange transaction tags within one hour
43	Procedure	Coordinate response to system emergencies
44	Procedure	Request emergency assistance from neighboring systems
45	Procedure	Assume sole control of designated telecommunication systems for use during an emergency
46	Procedure	Implement emergency procedures related to generating resources within a balancing area as directed by the reliability coordinator
47	Restoration	Direct the restoration of the transmission system following a major system outage, load shedding, islanding, or blackout

ITEM#	TYPE OF ACTIVITY	EMERGENCY OPERATIONS TASKS
48	Restoration	Ensure adequate protective relaying exists during all phases of the system restoration sequence
49	Restoration	Test or simulate system restoration procedures to validate restoration plans
50	Restoration	Following a partial or total system shutdown, implement the appropriate provisions and procedures of the system's restoration plan in a coordinated manner with adjacent systems
51	Restoration	Following a partial or total system shutdown, arrange for start-up and/or emergency power for generation units as required
52	Restoration	Following a partial or total system shutdown, arrange for and utilize emergency (backup) telecommunications facilities as required
53	Restoration	Following a partial or total system shutdown, restore the integrity of the Interconnection as soon as possible
54	Transmission	Formulate a plan to implement corrective actions when an operating reliability limit violation is anticipated
55	Transmission	Determine the cause and extent of transmission system disturbances and interruptions and the impact on other facilities
56	Transmission	Apply relief measures as necessary to permit re-synchronizing and reconnecting to the Interconnection when separated from the Interconnection
57	Transmission	Use manual load shedding to prevent imminent separation from the Interconnection due to transmission overloads, or to prevent voltage collapse
58	Transmission	Implement load shedding as directed by a transmission operator
59	Transmission	Identify and take appropriate actions when partial or full system islanding occurs
60	Voltage	Implement voltage reductions to alleviate system emergency conditions
61	Voltage	Identify and take appropriate actions when a partial or full system voltage collapse occurs

Attachment B: Emergency Operations Topics

These topics are identified as meeting the topic criteria for Emergency Operations training per Requirement 3 of this standard.

A. Recognition and Response to System Emergencies

1. Emergency drills and responses
2. Communication tools, protocols, coordination
3. Operating from backup control centers
4. System operations during unstudied situations
5. System Protection
6. Geomagnetic disturbances weather impacts on system operations
7. System Monitoring – voltage, equipment loading
8. Real-time contingency analysis
9. Offline system analysis tools
10. Monitoring backup plans
11. Sabotage, physical, and cyber threats and responses

B. Operating Policies Related to Emergency Operations

1. NERC standards that identify emergency operations practices (e.g. EOP Standards)
2. Regional reliability operating policies
3. Sub-regional policies and procedures
4. ISO/RTO policies and procedures

C. Power System Restoration Philosophy and Practices

1. Black start
2. Interconnection of islands – building islands
3. Load shedding – automatic (under-frequency and under-voltage) and manual
4. Load restoration philosophies

D. Interconnected Power System Operations

1. Operations coordination
2. Special protections systems
3. Special operating guides
4. Voltage and reactive control, including responding to eminent voltage collapse
5. Understanding the concepts of Interconnection Reliability Operating Limits versus System Operating Limits
6. DC tie operations and procedures during system emergencies
7. Thermal and dynamic limits
8. Unscheduled flow mitigation − congestion management
9. Local and regional line loading procedures
10. Radial load and generation operations and procedures
11. Tie line operations
12. E-tagging and Interchange Scheduling
13. Generating unit operating characteristics and limits, especially regarding reactive capabilities and the relationship between real and reactive output

E. Technologies and Tools

1. Forecasting tools
2. Power system study tools
3. Interchange Distribution Calculator (IDC)

F. Market Operations as They Relate to Emergency Operations

1. Market rules
2. Locational Marginal Pricing (LMP)
3. Transmission rights
4. OASIS
5. Tariffs
6. Fuel management
7. Real-time, hour-ahead and day-ahead tools

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Name:		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

[Insert brief background statement on the standards. Can use what is on the Standards Web site if needed.]

The [SAR or Standard Name] Drafting Team would like to receive industry comments on this group of standards [SAR]. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "[Title of Standard]" by **[Due Date in bold]**.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. **Question 1? If not, please explain in the comment area.**

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2. **Question 2? If not, please explain in the comment area.**

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3. **Question 3? If not, please explain in the comment area.**

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