NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

February 11, 2011

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: ***North American Electric Reliability Corporation,***
Docket Nos. RM11-___ -000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this filing in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations, seeking approval for one revised Reliability Standard, and the retirement of one existing approved Reliability Standard.

Specifically, NERC seeks FERC's approval of revised Reliability Standard EOP-008-1 – Loss of Control Center Functionality contained in **Exhibit A** to this petition; as well as approval to concurrently retire existing Reliability Standard EOP-008-0 – Loss of Control Center Functionality.

The proposed revised Reliability Standard EOP-08-1 was approved by the NERC Board of Trustees on August 5, 2010. NERC requests that EOP-008-1 be made effective in accordance with the effective date provision contained in the proposed Reliability Standard, which reads:

Effective Date: The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

EOP-008-0 is proposed to be retired concurrent with the implementation of EOP-008-1.

NERC's petition consists of the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the proposed Reliability Standard meets FERC's requirements;
- Reliability Standard EOP-008-1 submitted for approval (**Exhibit A**);
- Matrix of FERC Directives and Industry Comments Considered (**Exhibit B**)
- Standard Drafting Team Roster (**Exhibit C**); and
- The complete development record of the proposed revised Reliability Standard (**Exhibit D**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC	**)**	**Docket No. RM11-___-000**
RELIABILITY CORPORATION	**)**	

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF ONE EMERGENCY PREPAREDNESS AND OPERATIONS RELIABILITY STANDARD EOP-008-1 AND RETIREMENT OF ONE EXISTING RELIABILITY STANDARD EOP-008-0

Gerald W. Cauley
President and Chief Executive Officer
David N. Cook
Senior Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Holly A. Hawkins
Attorney
Willie L. Phillips
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
holly.hawkins@nerc.net
willie.phillips@nerc.net

February 11, 2011

TABLE OF CONTENTS

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") hereby requests the Federal Energy Regulatory Commission ("FERC" or the "Commission") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, revised Reliability Standard: EOP-008-1 - Loss of Control Center Functionality and the concurrent retirement of existing Reliability Standard: EOP-008-0 – Plans for Loss of Control Center Functionality. [2]

The NERC Board of Trustees approved Reliability Standard EOP-008-1 on August 5, 2010. NERC requests that FERC approve the proposed Reliability Standard and make it effective in accordance with the effective date provision[3] set forth in the Reliability Standard. **Exhibit A** to this filing sets forth the proposed Reliability Standard. **Exhibit B** contains the Matrix of FERC Directives and Industry Comments Considered in the development of these standards. **Exhibit C** contains the standard drafting team ("SDT") roster that developed the proposed Reliability Standard. **Exhibit D** contains the complete development record of the proposed Reliability Standard.

NERC is also filing this proposed Reliability Standard with applicable governmental authorities in Canada.

---

[1] 16 U.S.C. 824o.

[2] NERC has been certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).

[3] The proposed Effective Date in the standard is**:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

Gerald W. Cauley
President and CEO
David N. Cook*
Senior Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Holly A. Hawkins*
Attorney
Willie L. Phillips*
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
holly.hawkins@nerc.net
willie.phillips@nerc.net

*Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[4] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system ("BPS"), and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215 states that all users, owners and operators of the BPS in the United States will be subject to FERC-approved Reliability Standards.

[4] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005) (codified at 16 U.S.C. § 824o).

b. Basis for Approval of Proposed Reliability Standard

Section 39.5(a) of FERC's regulations requires the ERO to file with FERC for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective. FERC has the regulatory responsibility to approve standards that protect the reliability of the BPS. In discharging its responsibility to review, approve, and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5]

When evaluating proposed Reliability Standards, FERC is expected to give "due weight" to the technical expertise of the ERO. Order No. 672 provides guidance on the factors FERC will consider when determining whether proposed Reliability Standards meet the statutory criteria.[6]

c. Basis for Proposed Changes to Reliability Standard

The proposed Reliability Standard EOP-008-1—Loss of Control Center Functionality, works to ensure that a plan is in place for backup functionality and that facilities and personnel are prepared to implement that plan. During the implementation of the backup functionality, the responsible entities focus on maintaining the reliability of the Interconnection. The proposed standard applies to Transmission Operators, Balancing Authorities, and Reliability Coordinators.

---

[5] Section 215(d)(2) of the FPA, 16 U.S.C. § 824o(d)(2) (2000).

[6] *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs*., ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

The proposed standard represents a significant revision and improvement to the current enforceable standard. The proposed revisions improve the overall quality of the standard, eliminate gaps in the requirements, reduce ambiguity, eliminate “fill-in-the-blank” components, and address specific FERC Order 693 directives, as highlighted here and discussed in detail below. The proposed standard:

- clearly delineates what must be included in the plan for backup functionality;
- includes a provision for managing the risk to the BPS during the transition from primary to backup functionality;
- requires Reliability Coordinators to have a dedicated facility for its backup functionality;
- provides that Transmission Operators and Balancing Authorities can have either a dedicated facility or may contract for services to provide backup functionality;
- addresses the need for formal review and approval of the plan for backup functionality;
- mandates independence of the primary and backup capabilities;
- requires testing of the plan for backup functionality; and
- establishes a procedure for creating a plan to re-establish backup capability following a catastrophic situation.

The changes proposed reflect the consideration of a number of issues that were captured during NERC’s conversion of the former Operating Policies and Planning Standards to what is called the “Version 0” standards, as well as issues noted during the development of compliance measures for the Phase III and Phase IV Reliability Standards developed subsequent to Version 0 development, and the development of Violation Risk Factors in 2006.

In addition, the SDT addressed specific FERC Order No. 693 directives pertinent to this standard. These directives are described below, and are discussed in greater detail in **Attachment B** to this filing:

- provide for backup capabilities that, at a minimum, must be independent of the primary control center;
- provide for backup capabilities that, at a minimum, must be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center;
- provide for backup capabilities that, at a minimum, must provide for a minimum functionality to replicate the critical reliability functions of the primary control center;
- provide for backup capabilities that, at a minimum, must provide that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the BPS;
- provide for backup capabilities that, at a minimum, must include a requirement that all reliability coordinators have full backup control centers;
- provide for backup capabilities that, at a minimum, must require transmission operators and balancing authorities that have operational control over significant portions of generation and load to have minimum backup capabilities discussed above but may do so through contracting for these services instead of through dedicated backup control centers; and
- include large, centrally dispatched generation control centers.

d. Reliability Standards Development Procedure

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Standard Processes Manual*, which is incorporated into the Rules of Procedure as Appendix 3A.[7] In its ERO Certification Order, FERC found that NERC's proposed rules provide for reasonable notice and opportunity

[7] FERC approved the new Reliability *Standards Processes Manual* on September 3, 2010 (FERC Docket No. RR10-12-000), which replaced the *Reliability Standards Development Procedure Version 7* in its entirety. NERC developed the proposed EOP-008-1 standard in accordance with the *Reliability Standards Development Procedure Version 7*, because the *Standards Processes Manual* was not yet approved at the time of this standard's development.

for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards.[8]

The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard for submission to FERC.

The proposed Reliability Standard set out in **Exhibit A** has been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure Version 7*. The NERC Board of Trustees approved the proposed standard on August 5, 2010.

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS

This section summarizes the development of the proposed Reliability Standard, EOP-008-1, and provides evidence that the proposed Reliability Standard meets the criteria for approval set by FERC—that is, the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.

The standard drafting team roster is provided in **Exhibit C**. The complete development record for the proposed reliability standard is available in **Exhibit D**. This record includes the draft of the Reliability Standard through the development, the implementation plan, the ballot pool, and the final ballot results by registered ballot body members, stakeholder comments received during the development of the Reliability Standard, and an explanation of how those comments were considered in developing the Reliability Standard.

[8] Order No. 672 at PP 268, 270.

The purpose of EOP-008-1 is to ensure continued reliable operations of the BPS in the event that a control center becomes inoperable. The proposed EOP-008-1 standard applies to Reliability Coordinators, Transmission Operators, and Balancing Authorities and consists of eight requirements and associated parts, which provide:

- the need for a formally documented Operating Plan for backup functionality and what must be included in it;
- a provision for distributing the Operating Plan for backup functionality to the operators;
- the need for a Reliability Coordinator to have a dedicated backup control center facility;
- that a Balancing Authority or Transmission Operator shall have backup functionality that may be provided either through a facility of their own or through contracted services;
- annual review and approval of the Operating Plan for backup functionality;
- independence of the primary and backup capabilities;
- conducting and documenting tests of the Operating Plan for backup functionality; and
- the need for an approved plan to re-establish backup capability following a catastrophic event.

EOP-008-0 is proposed to be retired in its entirety. All of the requirements from that standard are now included in the proposed EOP-008-1 standard, as appropriate. The implementation plan for this standard requires compliance consistent with the proposed effective date of twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after NERC Board of Trustees adoption.

a. Demonstration that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

In order to approve a Reliability Standard proposed by the ERO, FERC must determine, after notice and opportunity for public hearing, that the standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[9] In Order No. 672, FERC identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. A review of the proposed Reliability Standards for consistency with these criteria is presented below.

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

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

The proposed Reliability Standard, EOP-008-1 – Loss of Control Center Functionality, specifically establishes the requirements for having an Operating Plan for backup functionality and all of the various elements such as review and approval, testing, and documentation required of an applicable entity necessary to ensure bulk power system reliability.

[9] Section 215(d)(2)(A) of the FPA; 18 C.F.R. §39.5.

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

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

The proposed Reliability Standard contains technically sound methods to achieve the goal of ensuring an Operating Plan for backup functionality is in place. The standard describes:

- What must be included in the Operating Plan for backup functionality, demonstrated in Requirement R1;
- To whom the Operating Plan for backup functionality must be distributed, demonstrated in Requirement R2;
- Specific requirements for Reliability Coordinators, in Requirement R3;
- Specific requirements for Transmission Operators and Balancing Authorities, in Requirement R4;
- When the Operating Plan for backup functionality is to be updated, as shown in Requirement R5;
- Maintaining the independence of the primary and backup capabilities, demonstrated in Requirement R6;
- Testing as shown in Requirement R7; and
- Establishing the need for a plan to re-establish backup capability following a catastrophic event, as shown in Requirement R8.

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

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

The proposed Reliability Standard is applicable to users, owners and operators of the BPS, and not others. The proposed standard is specifically applicable to Reliability Coordinators, Transmission Operators, and Balancing Authorities. Each of those entities is a user, owner or operator of the BPS.

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

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

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply. Each requirement clearly states the applicable entity (ies) and what they are required to do. For example, the revised standard now clearly distinguished the requirements applicable to Reliability Coordinators (Requirement R4) and Transmission Operators and Balancing Authorities (Requirement R5).

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

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

The proposed Reliability Standard includes clear and understandable consequences. Each primary requirement was assigned a Violation Risk Factor ("VRF") and a Violation Severity Level ("VSL"), which support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in Commission-approved standards, as defined in the ERO Sanction Guidelines. In addition to the NERC VSL guidelines, VSLs for the proposed standard are also consistent with the VSL guidelines established by FERC. An explanation of NERC's review of these VSLs for consistency with FERC's VSL guidelines is included in Section V of this document.

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

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

The proposed Reliability Standard identifies clear and objective criteria in the language of the requirements to enable enforcement of the Standard in a consistent and non-preferential manner. Each requirement has an associated measure, and each requirement is clear in its expectations such that development of compliance enforcement objectives through the Reliability Standard Audit Worksheets is straightforward. The language in the requirements is unambiguous with respect to what is expected of the applicable entity.

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

   Order No. 672 at P 328. *The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability*

> *goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.*

The proposed Reliability Standard achieves its reliability goal effectively and efficiently, not necessarily reflecting "best practices" without regard to implementation costs. Care was taken to expand the requirements to meet the reliability objectives without unduly burdening applicable entities. For example, requirements for dedicated facilities for Transmission Operators and Balancing Authorities are limited when compared to those for the Reliability Coordinator. Moreover, testing of the Operating Plan for backup functionality is restricted to two hours per year. This is reasonable because it allows an entity to run across an hour boundary, which is an important time mark in SCADA. Two hours also sufficiently ensures that all various software functions will have run, thereby ensuring more complete test results.

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

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

The proposed Reliability Standard is more stringent than the EOP-008-0 standard in several areas. Testing the Operating Plan for backup functionality (Requirement R7), the need to re-establish backup capability following a catastrophic event (Requirement R8), and mitigating the risk to the BPS during transition from the primary to the backup functionality (Requirement R1, part 1.6.2) all reflect significantly increased responsibilities for applicable entities.

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

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

The proposed Reliability Standard does not reflect any differentiation in compliance with requirements based on size. If an entity has responsibility for restoration tasks, it must adhere to the requirements regardless of size. However, the SDT has considered costs that may be a factor to smaller entities by allowing for contracted services for Transmission Operators and Balancing Authorities.

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

   Order No. 672 at P 331. *A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.*

The proposed Reliability Standard is designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach. The standard as drafted proposes no regional differences or variances.

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

> Order No. 672 at P 332. *As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another*.

There is no basis for anticipating that the proposed Reliability Standard will adversely affect competition or restrict available transmission capability.

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

> Order No. 672 at P 333. *In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances 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*.

The proposed Reliability Standard identifies an effective date that is reasonable. Given that compliance is already required for EOP-008-0, NERC believes the proposed effective date represents a reasonable time frame to allow entities to adequately prepare for compliance with the new requirements.

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

> Order No. 672 at P 334. *Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to*

> *arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.*

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

The proposed Reliability Standard set out in **Exhibit A** has been developed and approved by industry stakeholders using the process found in NERC's *Reliability Standards Development Procedure*, and was approved by the NERC Board of Trustees on August 5, 2010 for filing with FERC. Therefore, NERC has utilized its approved standard development process, in effect at the time of its development, in a manner that is open and fair.

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

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

No environmental, social, or other goals are reflected, nor do they enter into consideration, apart from ensuring that backup functionality is implemented in such a manner that Interconnection reliability is maintained.

15. **Proposed Reliability Standards must consider any other relevant factors**

> Order No. 672 at P 323. *In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.*
>
> Order No. 672 at P 337. *In applying the legal standard to review of a proposed Reliability Standard, FERC will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. FERC may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.*

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

V. Violation Risk Factors and Violation Severity Levels

The proposed Reliability Standard includes VRFs and VSLs that are specific to individual requirements. The ranges of penalties for violations of standards are based on the applicable VRFs and VSLs and will be administered based on the Sanctions Table and supporting penalty determination process described in FERC-approved NERC Sanction Guidelines, which can be found in Appendix 4B of NERC's Rules of Procedure. Consistent with NERC's August 10, 2009 informational filing, assignments of VRFs and VSLs were made at the main requirement level of each standard.

a. Justification for Assignment of Violation Risk Factors in EOP-008-1

VRF assignments for EOP-008-1 were based on the criteria stated in the NERC VRF guidelines:

- ***High Risk Requirement*****—**A requirement that, if violated, could directly cause or contribute to BPS instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BPS instability, separation, or a cascading sequence of failures, or could place the BPS at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
- ***Medium Risk Requirement*****—**A requirement that, if violated, could directly affect the electrical state or the capability of the BPS, or the ability to effectively monitor and control the BPS. However, violation of a medium risk requirement is unlikely to lead to BPS instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to

lead to BPS instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

- ***Lower Risk Requirement—***A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor and control the BPS; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BPS, or the ability to effectively monitor, control, or restore the BPS. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Guidelines for setting VRFs, outlined in the VRF Rehearing order:[10]

- **Guideline (1) — Consistency with the Conclusions of the Final Blackout Report**
  FERC seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

  In the VRF Rehearing Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS.[11]

- **Guideline (2) — Consistency within a Reliability Standard**
  FERC expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement VRF assignment.

- **Guideline (3) — Consistency among Reliability Standards**

[10] *North American Electric Reliability Corp.*, 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[11] *Id*. at footnote 14 ("The areas are emergency operations; vegetation management; operator personnel training; protection systems and their coordination; operating tools and backup facilities; reactive power and voltage control; system modeling and data exchange; communication protocol and facilities; requirements to determine equipment ratings; synchronized data recorders; clearer criteria for operationally critical facilities; and appropriate use of Transmission Loading Relief.").

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

- **Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level**
  Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

- **Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation**
  Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, whereas Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT therefore determined that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eight proposed requirements in EOP-008-1. Of these eight requirements, Requirements R2 and R5 were assigned a "Lower" VRF, which were seen as mainly administrative in nature. All other requirements were given a "Medium" VRF. The following analysis demonstrates that the VRFs proposed for each requirement in EOP-008-1 meet the FERC Guidelines for assessing VRFs:

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
R1	The requirement	There is a similar requirement	Failure to have an	EOP-008-1,

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
	has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.	(Requirement R1) in proposed EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the creation of a plan: EOP-005-2 for a restoration plan and EOP-008-1 for a backup plan. The VRF assigned to EOP-008-1, Requirement R1 is lower than EOP-005-2, Requirement R1. The SDT recognizes that the VRF for EOP-008-1, Requirement R1 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however, the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to BPS instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to create an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to have an Operating Plan for backup functionality may put the applicable entity in	Operating Plan for backup functionality could directly affect the electrical state or the capability of the BPS, and could affect the applicable entity's ability to effectively monitor and control the BPS. However, violation of this requirement is unlikely to lead to BPS instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the BPS regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to have an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.	Requirement R1 contains only one objective, therefore only one VRF was assigned.

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
		a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to have an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred.		
R2	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	EOP-008-1, Requirement R2 is a new requirement, so there are no comparable requirements with which to compare VRFs.	Failure to have a copy of the Operating Plan for backup functionality at each of its control locations should not have an adverse impact on the BPS because operations at the different locations should be essentially identical. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.	EOP-008-1, Requirement R2 contains only one objective, therefore only one VRF was assigned.
R3	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	EOP-008-1, Requirement R3 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs. However, the SDT did assign the same VRF to EOP-008-1, Requirement R4 which is a similar requirement applying to Transmission Operators and Balancing Authorities. The assignment of the "Medium" VRF was made based on the premise that failure to have a backup control center facility (provided through its own dedicated backup facility or at another	Failure to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) will impact the situational awareness of the Reliability Coordinator, and thus could affect the Reliability Coordinator's ability to effectively monitor and control the BPS, however violation of this requirement is unlikely to lead to BPS instability, separation or	EOP-008-1, Requirement R3 contains only one objective, therefore only one VRF was assigned.

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
		entity's control center), by itself, would not directly cause or contribute to BPS instability, separation, or a cascading sequence of failures. The Reliability Coordinator is always responsible for maintaining the reliability of the BPS regardless of the situation. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when a Reliability Coordinator fails to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center). The SDT agrees that if the Reliability Coordinator fails to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center), this failure will put the Reliability Coordinator in a position where they are not as prepared as they should be to address the situation. However, even if the Reliability Coordinator failed to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center), the Reliability Coordinator is still required to maintain control and awareness of the BPS. In addition, the Transmission Operators and Balancing Authorities who	cascading failures. The Reliability Coordinator is required to maintain control and awareness of the BPS at all times. In addition, the Transmission Operators and Balancing Authorities who report to the affected Reliability Coordinator would still be expected to be operating in 'normal' mode thus providing comprehensive coverage of the BPS in the timeframe where the Reliability Coordinator has a problem. Therefore, the failure of a Reliability Coordinator to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) should not directly result in instability, separation, or cascading failures. Thus, this requirement meets the criteria for a Medium VRF.	

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
		report to the affected Reliability Coordinator would still be expected to be operating in 'normal' mode thus providing comprehensive coverage of the BPS in the timeframe where the Reliability Coordinator has a problem.		
R4	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	EOP-008-1, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs. However, the SDT did assign the same VRF to EOP-008-1, Requirement R3 which is a similar requirement applying to Reliability Coordinators. The assignment of the "Medium" VRF was made based on the premise that failure to have backup functionality (provided either through a facility or contracted services), by itself, would not directly cause or contribute to BPS instability, separation, or a cascading sequence of failures. The Transmission Operator and Balancing Authority are always responsible for maintaining the reliability of the BPS regardless of the situation. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when a Transmission Operator or Balancing Authority fails to have backup functionality (provided either through a facility or contracted services). The SDT agrees that if the	Failure to have backup functionality (provided either through a facility or contracted services) will impact the situational awareness of the Transmission Operator or Balancing Authority, and thus could affect the Transmission Operator's or Balancing Authority's ability to effectively monitor and control the BPS, however violation of this requirement is unlikely to lead to BPS instability, separation or cascading failures. The Transmission Operator or Balancing Authority is required to maintain control and awareness of the BPS at all times. In addition, the Reliability Coordinator who 'sits' above the affected Transmission Operator or Balancing Authority would still be expected to be operating in 'normal' mode thus providing comprehensive coverage of the BPS in the timeframe where the Transmission Operator or Balancing Authority has a problem. Therefore, the	EOP-008-1, Requirement R4 has only one objective, therefore only one VRF was assigned.

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
		Transmission Operator or Balancing Authority fails to have backup functionality (provided either through a facility or contracted services), this failure will put the Transmission Operator or Balancing Authority in a position where they are not as prepared as they should be to address the situation. However, even if the Transmission Operator or Balancing Authority failed to have backup functionality (provided either through a facility or contracted services), the Transmission Operator or Balancing Authority is still required to maintain control and awareness of the BPS. In addition, the Reliability Coordinator who 'sits' above the affected Transmission Operator or Balancing Authority would still be expected to be operating in 'normal' mode thus providing comprehensive coverage of the BPS in the timeframe where the Transmission Operator or Balancing Authority has a problem.	failure of a Transmission Operator or Balancing Authority to have backup functionality (provided either through a facility or contracted services) should not directly result in instability, separation, or cascading failures. Thus, this requirement meets the criteria for a Medium VRF.	
R5	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	There is a similar requirement (Requirement R4) in proposed EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the update of a plan: EOP-005-2 for a restoration plan and EOP-008-1 for a backup plan. The VRF assigned to EOP-008-1, Requirement R5 is lower than EOP-005-2, Requirement R4.	Failure to update an Operating Plan for backup functionality could directly affect the electrical state or the capability of the BPS, and could affect the applicable entity's ability to effectively monitor and control the BPS. However, violation of this requirement is	EOP-008-1, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
		The SDT recognizes that the VRF for EOP-008-1, Requirement R5 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to update an Operating Plan for backup functionality, by itself, would not directly cause or contribute to BPS instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to update an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to update an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to update an Operating Plan for backup functionality, it would	unlikely to lead to BPS instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the BPS regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to update an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.	

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
		still be expected to handle the situation if it occurred. Additionally, the assignment of a Medium VRF to this requirement is consistent with the VRF assignment for Requirement R1.		
R6	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	EOP-008-1, Requirement R6 is a new requirement, so there are no comparable requirements with which to compare VRFs.	EOP-008-1, Requirement R6 addresses the situation applicable entities primary and backup capabilities can't depend on each other. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.	EOP-008-1, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.
R7	Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	Consistency among Reliability Standards. EOP-008-1, Requirement R7 is a new requirement, so there are no comparable requirements with which to compare VRFs.	Consistency with NERC's Definition of a VRF. EOP-008-1, Requirement R7 mandates testing of an applicable entity's Operating Plan for backup capability. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did not test their Operating Plan for backup capability it is not clear that this could directly lead, without any other violations of any other requirements, to	Treatment of Requirements that Co-mingle More Than One Objective. IRO-010-1a Requirements R1 and R2 each address a single objective and each has a single VRF.

Req.	**Guideline 2** Consistency within a Reliability Standard.	**Guideline 3** Consistency among Reliability Standards.	**Guideline 4** Consistency with NERC's Definition of a VRF.	**Guideline 5** Treatment of Requirements that Co-mingle More Than One Objective.
			instability, separation, or cascading failures.	
R8	The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.	EOP-008-1, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.	EOP-008-1, Requirement R8 mandates that entities provide a plan for re-establishing backup capabilities following a catastrophic failure. A failure to provide this plan does not affect the applicable entity's ability to effectively monitor and control the BPS. Violation of this requirement is unlikely, by itself, to lead to BPS instability, separation, or cascading failures, thus the assignment of a "Medium" VRF.	EOP-008-1, Requirement R8 addresses a single objective and has a single VRF.

b. Justification for Assignment of Violation Severity Levels for EOP-008-1

In developing the VSLs for the EOP-008-1 standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the

requirement.	requirement.	value in meeting the intent of the requirement.	product delivered cannot be used in meeting the intent of the requirement.

The SDT also considered the FERC guidelines for evaluating VSLs, which include:

Guideline 1: Violation Severity Level assignments should not have the unintended consequence of lowering the current level of compliance;

Guideline 2: Violation Severity Level assignments should ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties;

a) the single VSL assignment category for “binary” requirements is not consistent;
b) the VSL assignments contain ambiguous language.

Guideline 3: Violation Severity Level assignments should be consistent with the corresponding requirement; and

Guideline 4: Violation Severity Level assignments should be based on a single violation, not on a cumulative number of violations.

The following analysis demonstrates that the VSLs proposed for each requirement in

EOP-008-1 are consistent with the FERC Guidelines for assessing VSLs:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Consistent with NERC's VSL guidelines.	The most comparable VSLs for a similar requirement are for the proposed EOP-005-2, Requirement R1. Those VSLs are based on missing one element for Lower, two for Moderate, and so forth, which is analogous to the VSL structure for EOP-008-1, Requirement R1. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2a is inapplicable.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Consistent with NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2a is inapplicable.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3	Consistent with NERC's VSL guidelines.	The proposed requirement is new and there are	The proposed VSLs do not use any ambiguous terminology, thereby	The proposed VSLs use the same terminology	The VSLs are based on a single violation

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
.		no comparable VSLs.	supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2a is inapplicable.	as used in the associated requirement, and are, therefore, consistent with the requirement.	and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Consistent with NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore,	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
			violations. Guideline 2a is inapplicable.	consistent with the requirement.	

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Consistent with NERC's VSL guidelines.	The most comparable VSLs for a similar requirement are for the proposed EOP-005-2, Requirement R4. Those VSLs are based on late distribution of a	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2a is inapplicable.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		plan which is analogous to the VSLs for EOP-008-1, Requirement R5. The VSLs assignments are similar between the two standards. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

R #	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R 6.	Consistent with NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2a is inapplicable.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R #	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R 7.	Consistent with NERC's VSL guidelines.	The proposed requirement is new and there are no comparable	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity	The proposed VSLs use the same terminology as used in the	The VSLs are based on a single violation and not

R #	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		VSLs.	and consistency in the determination of similar penalties for similar violations. Guideline 2a is inapplicable.	associated requirement, and are, therefore, consistent with the requirement.	cumulative violations.

R #	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R 8.	Consistent with NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Guideline 2a	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the	The VSLs are based on a single violation and not cumulative violations.

R #	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
			is inapplicable.	requirement.	

VI. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

a. Development History

On October 26, 2006, NERC received, and the Standards Committee accepted, a standards authorization request ("SAR") for Project 2006-04, which included revisions to EOP-008-0. The SAR was posted for two industry comment opportunities and then approved by the Standards Committee for standard development on May 10, 2007.

The SDT posted the draft standard for initial industry comment from February 11, 2008 to March 7, 2008. In response, 45 sets of comments were received from representatives of 75 companies and 9 of the 10 industry segments. Comments primarily dealt with applicability issues for Transmission Operators, contents of the Operating Plan for backup functionality, transition timeframes, and clarification of when backup functionality is required.

The SDT revised the draft standard accordingly and re-posted for industry comment for a second time from August 29, 2008 to October 9, 2008, a 45-day posting. This time, 38 sets of comments were received from 50 companies representing 8 of the 10 industry segments. Comments received mainly focused on continuing questions on applicability provisions for Transmission Operators, measures, VSLs, length of the Implementation Plan timeframe for compliance, and whether there was a requirement for a tertiary facility or functionality.

Once again, the SDT revised the draft standard to accommodate industry concerns and posted for a third time between March 19, 2009 and April 15, 2009. In response to the third posting, there were 36 sets of comments from 60 companies representing 8 of the 10 industry segments. Comments dealt with clarifications on the need for certified operators at contracting facilities and what independence of capabilities meant. Nearly all of the commenters agreed that the draft standard was ready for balloting. The Standards Committee approved the standard for balloting on August 7, 2009.

The SDT faced a number of key issues during the standard development period:

1. **Exclusions for Transmission Operators based on size.** The SDT debated at great length as to whether there should be applicability exclusions for Transmission Operators based on size. This discussion was prompted in part by a FERC Order No. 693 directive. The SDT tried twice to craft a reasonable exclusion and twice the comments received from industry did not support such exclusions. Ultimately, the SDT decided to remove the exclusion.
2. **Determining a transition timeframe.** Some commenters thought the 2 hour transition timeframe was too broad, others too limited. Still, others argued that the timeframe seemed to weaken the current requirement. The SDT attempted to

develop a reasonable number that would allow for a backup to be placed sufficiently far away so that the chances of a single catastrophe affecting both sites were minimal, versus having it so far away that there may be a serious gap in reliability during the intervening time before the backup is operational. The SDT decided that 2 hours was a reasonable number and that the current requirement is not weakened by such a value. The basis for this conclusion was that the revised standard calls for more accountability during the transition and requires testing of the Operating Plan for backup functionality, thus, increasing the likelihood that the backup will work as planned.

3. **Developing testing requirements for the Operating Plan for backup functionality.** Some commenters argued that a 2 hour testing requirement was too prescriptive. However, the SDT determined that 2 hours provided an adequate test that would go across an hour boundary and thereby inspect all necessary programs.

NERC conducted the initial ballot from September 16, 2009 through September 29, 2009. With an 82.69% quorum participating in the ballot, the proposed Reliability Standard achieved a weighted segment vote of 72.86%. 48 negative ballots were submitted for the initial ballot, and all of those negative ballots included a comment. There were three main themes to the comments supplied with the initial balloting:

1. Concerns about the transition timeframe;
2. Concerns about independence of facilities; and
3. The need for tertiary capability.

The Standards Committee reviewed the negative industry comments and decided on November 12, 2009, that the standard should be remanded to the SDT for another 30-day posting to clarify some of the commenter's concerns. The SDT responded to the Standard Committee's request and re-posted the standard for a 30-day industry comment period on February 4, 2010.

The commenters agreed that the standard was ready for balloting, and the Standards Committee authorized the balloting process to begin on May 13, 2010. The 30-day pre-ballot period began on May 24, 2010. NERC conducted the 'second' initial ballot from June 23, 2010 through July 6, 2010. With an 89.05% quorum participating in the ballot, the proposed Reliability Standard achieved a weighted segment vote of 79.45%. There were 30 negative ballots submitted for the initial ballot, and all of those negative ballots included a comment. There were 2 main themes to the comments submitted with the initial balloting.

1. Concerns about the timing and need for updating the plan for backup functionality; and

2. Use of the term 'situational awareness'.

The SDT posted its "Consideration of Comments" reports to the "second" initial ballot comments on July 15, 2010, and NERC conducted the recirculation ballot from July 16, 2010 through July 26, 2010. With a 93.43 % quorum participating in the ballot, the proposed Reliability Standard achieved a weighted segment vote of 85.22%. The proposed Reliability Standard achieved the required two-thirds weighted segment vote and at least a 75 percent quorum of the ballot pool. The NERC Board of Trustees adopted the standards during its August 5, 2010 meeting.

VII. CONCLUSION

For the reasons stated above, NERC respectively requests that FERC approve revised Reliability Standard: EOP-008-1— Loss of Control Center Functionality, as well as the retirement of existing Reliability Standard: EOP-008-0 — Plans for Loss of Control Center Functionality, as set out in **Exhibit A**, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC's regulations. NERC requests that approvals be made effective in accordance with the effective date provisions set forth in the proposed Reliability Standard.

Respectfully submitted,

/s/ Holly A. Hawkins

Gerald W. Cauley
President and Chief Executive Officer
David N. Cook
Senior Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Holly A. Hawkins
Attorney
Willie L. Phillips
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
holly.hawkins@nerc.net
willie.phillips@nerc.net

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 11th day of February, 2011.

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

Exhibit A

Reliability Standards Proposed for Approval

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.

5. **Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Voice communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include at a minimum:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup

functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's six Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's six Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's six Parts (1.1 through 1.6).	The responsible entity did not have a current Operating Plan for backup functionality.
R2	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3.
R4.	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4.

R#	Lower	Moderate	High	Severe
	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Medium VRF.	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a High VRF.	
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 0.5 continuous hours.

R#	Lower	Moderate	High	Severe
			for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	05/05/10	Approved by the Board of Trustees	Project 2006-04 Major re-write to accommodate changes noted in project file

Exhibit B

Matrix of Issues Considered

Source	Standard No.	Project No	Language	Reference
Fill in the Blank Team	EOP-008-0	2006-04	No comments	Nothing required.
Version 0 Team	EOP-008-0	2006-04	How does staff know control center is lost? (Note – A system health monitor concept or equivalent functionality is what is desired here.)	To the extent that this statement applies to backup functionality as described in this standard, this is covered in Requirement R1, part 1.4.1.
Version 0 Team	EOP-008-0	2006-04	How is backup control achieved?	Requirement R1, part 1.1
Version 0 Team	EOP-008-0	2006-04	Max. time to restore capabilities	Requirement R1, part 1.5
VRFs Team	EOP-008-0	2006-04	R1 - Not having a written plan does not directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading	VRFs assigned to every requirement
VRFs Team	EOP-008-0	2006-04	R1.1 - Not having a written plan is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.	VRFs assigned to every requirement
FERC Order 693	EOP-008-0	2006-04	663 - Provide for backup capabilities that, at a minimum, must be independent of the primary control center	Proposed EOP-008-1, Requirement R6
FERC Order 693	EOP-008-0	2006-04	663 - Provide for backup capabilities that, at a minimum, must be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center.	Proposed EOP-008-1, Requirement R1, part 1.1
FERC Order 693	EOP-008-0	2006-04	663 - Provide for backup capabilities that, at a minimum, must provide for a minimum functionality to replicate the critical reliability functions of the primary control center.	Proposed EOP-008-1, Requirement R3 for Reliability Coordinator Proposed EOP-008-1, Requirement R4 for Transmission Operator & Balancing Authority
FERC Order 693	EOP-008-0	2006-04	672 - Provide for backup capabilities that, at a minimum, must provide that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the bulk power system.	Proposed EOP-008-1, Requirement R3 for Reliability Coordinator Proposed EOP-008-1, Requirement R4 for Transmission Operator & Balancing Authority

Source	Standard No.	Project No	Language	Reference
FERC Order 693	EOP-008-0	2006-04	670 - Provide for backup capabilities that, at a minimum, must include a requirement that all reliability coordinators have full backup control centers;	Proposed EOP-008-1, Requirement R3 for Reliability Coordinator
FERC Order 693	EOP-008-0	2006-04	663 - Provide for backup capabilities that, at a minimum, must require transmission operators and balancing authorities that have operational control over significant portions of generation and load to have minimum backup capabilities discussed above but may do so through contracting for these services instead of through dedicated backup control centers.	Proposed EOP-008-1, Requirement R4 for Transmission Operator & Balancing Authority
FERC Order 693	EOP-008-0	2006-04	670 - Include large, centrally dispatched generation control centers.	Delegation agreements between Balancing Authorities and Generator Operators, which are enforced by compliance auditors, cover this item. No action taken. (Note – FERC staff has indicated that they are not comfortable with this resolution and that they preferred to retain the disputed Requirement R3 that NERC staff deleted from the standard.)

Exhibit C

Standard Drafting Team Roster

Backup Facilities Standard Drafting Team Roster (Project 2006-04)

Chairman	Samuel Brattini	KEMA Consulting 4377 Country Line Road Chalfont, Pennsylvania 18914	(215) 997-4500 (215) 997-3818 Fx sam.brattini@ us.kema.com
Vice Chairman	Michael Schiavone Transmission Control Center	Niagara Mohawk Power Corp. 7437 Henry Clay Blvd HCB-3 Liverpool, New York 13088	(315) 460-2472 (315) 460-2494 Fx michael.schiavone@ us.ngrid.com
	Tom Bowe Executive Director Reliability Integration	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 666-4776 (610) 666-4282 Fx bowet@pjm.com
	Blaine R. Dinwiddie Division Manager	Omaha Public Power District 4325 Jones Plaza Omaha, Nebraska 68105	(402) 552-5970 (402) 552-5679 Fx bdinwiddie@ oppd.com
	Charles W. Jenkins Vice President, System Operations	Oncor Electric Delivery 2233-B Mountain Creek Parkway Dallas, Texas 75211-6716	(214) 743-6865 (972) 263-6710 Fx c.w.jenkins@ oncor.com
	Glenn Kaht Senior Engineer, Compliance	ReliabilityFirst Corporation 11412 Siedschlag Rd. Spring Grove, Illinois 60081	330-247-3063 (330) 456-5408 Fx glenn.kaht@ rfirst.org
	Barry R. Lawson Manager, Power Delivery	National Rural Electric Cooperative Association 4301 Wilson Boulevard Mailcode EP11-253 Arlington, Virginia 22203	(703) 907-5781 (703) 907-5517 Fx barry.lawson@ nreca.coop
	Sara McCoy Senior Engineer - Transmission Services	SRP Mail Station POB013 P.O. Box 52025 Phoenix, Arizona 85072	(602) 236-3941 (602) 236-3808 Fx sara.mccoy@ srpnet.com
	Melinda K. Montgomery Transmission Business Manager, Operations	Entergy Services, Inc. 5201 West Barraque Pine Bluff, Arkansas 71602	(870) 329-7666 (870) 541-3964 Fx mmontg3@ entergy.com
	Keith Porterfield	Georgia Systems Operations Corporation 2100 E. Exchange Place Tucker, Georgia 30084	(770) 270-7374 kgp@gasoc.com
	John Procyk	Hydro One, Inc. 49 Sarjeant Drive Barrie, Ontario L4N 4V9	(705) 792-3210 john.procyk@ hydroone.com

	James Vermillion	Associated Electric Cooperative, Inc. 2814 South Golden Springfield, Missouri 65801	(417) 885-9307 jvermillion@ aeci.org
NERC Staff Coordinator	Edward J. Dobrowolski Standards Development Coordinator	North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx ed.dobrowolski@ nerc.net
NERC Staff	Maureen E. Long Standards Process Manager	North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx maureen.long@ nerc.net

Exhibit D

Record of Development of Proposed Reliability Standards

Project 2006-04
Back-up Facilities

Related Files

Status:
Reliability Standard EOP-008-1 and its associated implementation plan were approved by the Board of Trustees on August 5, 2010. and will be filed for approval with regulatory authorities.

Purpose / Industry Need:
The purpose of revising these standards is to:

- Provide an adequate level of reliability for the North American bulk power systems — the standards are complete and the requirements are set at an appropriate level to ensure reliability.
- Ensure they are enforceable as mandatory reliability standards with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
- Incorporate other general improvements described in the standards development work plan (see attachments).
- Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in the attached review sheets.
- Satisfy the standards procedure requirement for five-year review of the standards.

As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada , the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards, Phase III & IV standards, and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and Phase III & IV translations. The two standards in this set are both Version 0 standards.

Draft	Action	Dates	Results	Consideration of Comments
EOP-008-1 – Backup Facilities Clean**(63)** | Redline to Initial Ballot**(64)**	Recirculation Ballot Vote>> | Info**(65)**	07/16/10 - 07/26/10 (closed)	Summary**(67)** Full Record**(66)**	

Draft 6 EOP-008-1 – Backup Facilities Clean**(54)** | Redline to last posting**(55)**	Initial Ballot and Non-binding VRF/VSL Poll Vote | Info**(57)**	06/23/10 - 07/06/10 (closed)	Summary**(60)** Full Record**(59)** Non-binding Poll Results**(58)**	Consideration of Comment**(62)** Non-binding Poll Consideration of Comments**(61)**
	Pre-ballot Review Info**(56)** | Join>>	05/21/10 - 06/21/10 (closed)		
Draft 5 EOP-008-1 – Backup Facilities Clean**(49)** | Redline to last posting**(50)** Implementation Plan Clean**(47)** | Redline to last posting**(48)** Supporting Materials: Comment Form (Word)**(46)** VRF and VSL Justification**(45)**	Comment Period Submit Comments>> Info**(51)**	02/04/10 - 03/08/10 (closed)	Comments Received**(52)**	Consideration of Comments**(53)**
Draft 4 EOP-008-1 – Backup Facilities Clean**(38)** | Redline to last posting**(39)** **Supporting Materials:** Implementation Plan**(37)**	Initial Ballot Info>>**(41)** | Vote>>	09/16/09 - 09/28/09 (closed)	Summary**(43)** Full Record**(42)**	Consideration of Comments**(44)**
	Pre-ballot Review Info>>**(40)** | Join>>	08/17/09 - 09/16/09 (closed)		
Draft 3 EOP-008-1 – Backup Facilities Clean**(32)** | Redline to last posting**(33)** **Supporting Materials:** Comment Form (Word)**(31)** Implementation Plan Clean**(29)** | Redline to last posting**(30)**	Comment Period Info>>**(34)** Submit Comments>>	03/17/09 - 04/15/09 (closed)	Comments Received**(35)**	Consideration of Comments**(36)**

Draft 2 EOP-008-1 – Backup Facilities Clean**(24)** | Redline to last posting**(25)** **Supporting Materials:** Comment Form (Word)**(23)** Implementation Plan**(22)**	Comment Period Info>>**(26)** Submit Comments>>	08/26/08 – 10/09/08 (closed)	Comments Received**(27)**	Consideration of Comments**(28)**
Draft 1 EOP-008-1 Backup Facilities Draft Standard Version 1**(17)**	Comment Period Info>>**(19)** Comment Form>>**(18)**	02/07/08 - 03/07/08 (closed)	Comments Received**(20)**	Consideration of Comments**(21)**
Backup Facilities Standard Drafting Team Final SAR Version 2 Clean**(13)** | Redline to last posting**(14)**	Nomination Period Info>>**(16)** Nomination Form>>**(15)**	04/30/07 - 05/11/07 (closed)		
Draft 2 Back-up Facilities Draft SAR Version 2 Clean**(7)** | Redline to last posting**(8)**	Comment Period Info>>**(10)** Comment Form>>**(9)**	02/15/07 - 03/16/07 (Closed)	Comments Received**(11)**	Consideration of Comments**(12)**
Draft 1 Back-up Facilities Draft SAR Version 1**(2)**	Comment Period Info>>**(4)** Comment Form>>**(3)**	11/06/06 - 12/05/06 (closed)	Comments Received**(5)**	Consideration of Comments**(6)**
Back-up Facilities SAR Drafting Team	Nomination Form>>**(1)**	11/06/06 - 11/17/06 (closed)		

To download a file click on the file using your right mouse button, then save it to your computer in a directory of your choice.

Documents in the PDF format require use of the Adobe Reader® software. Free Adobe Reader® software allows anyone view and print Adobe Portable Document Format (PDF) files. For more information download the Adobe Reader User Guide.

Get Adobe Reader

Nomination Form — Back-up Facilities SAR Drafting Team

Please return this form to sarcomm@nerc.com by November 17, 2006. For questions, please contact Richard Schneider at 609-452-8060 or richard.schneider@nerc.net

Please note this drafting team will likely meet initially in December 2006 (probably by WebEx) to respond to the comments on the SAR.

<table>
<tr><td colspan="3">Name:

Organization:

Address:

Office Telephone:

E-mail:</td></tr>
<tr><td colspan="3">Please briefly describe your experience and qualifications to serve on the Back-up Facilities SAR Drafting Team. Prefer candidates with expertise in specifying facilities or in developing backup facility plans for a Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Distribution Provider. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.</td></tr>
<tr><td>I represent the following NERC Reliability Region(s) (check all that apply):</td><td colspan="2">I represent the following Industry Segment (check one):</td></tr>
<tr><td rowspan="4">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs, ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
</table>

☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations and Regional Entities

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Reliability Coordinator	☐ Transmission Service Provider
☐ Balancing Authority	☐ Transmission Owner
☐ Interchange Authority	☐ Load Serving Entity
☐ Planning Authority	☐ Distribution Provider
☐ Transmission Operator	☐ Purchasing-selling Entity
☐ Generator Operator	☐ Generator Owner
☐ Transmission Planner	☐ Resource Planner
	☐ Market Operator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the NERC Glossary of Terms, which is downloadable from the NERC Web site.

Standard Authorization Request Form

Title of Proposed Standard	Back-up Facilities Project 2006-04
Request Date	October 26, 2006

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Reliability Standards Development Plan: 2007 – 2009	☐	New Standard
Primary Contact Richard Schneider (To be replaced by SAR DT Chair when the SAR DT is appointed)	X	Revision to existing Standard
Telephone 609-452-8060 Fax	☐	Withdrawal of existing Standard
E-mail Richard.schneider@nerc.net	☐	Urgent Action

Purpose

Applicable Standards: COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

The purpose of revising these standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems — the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in the standards development work plan (see attachments).
4. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in the attached review sheets.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need

As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards, Phase III & IV standards, and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and Phase III & IV translations. The two standards in this set are both Version 0 standards.

Brief Description

A study of the backup capabilities that are needed to support reliable operations is required as part of this project.

The requirements in EOP-008 need additional specificity. The study conducted before this standard is finalized should look at the facility requirements identified in the certification standards and identify which of these are essential to reliable operations.

There are backup facility requirements in some other standards, and those requirements should be moved into this standard.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest Reliability Authority.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☐	Planning Authority	Plans the Bulk Electric System.
☐	Resource Planner	Develops a long-term (>one year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐	Transmission Planner	Develops a long-term (>one year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities.
X	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
X	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer.
☐	Generator Owner	Owns and maintains generation unit(s).
X	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity, and all necessary Interconnected Operations Services as required.
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	**Explanation**

Related SARs

SAR ID	**Explanation**

Regional Differences

Region	**Explanation**
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Review Form **Project 2006-04 Back-up Facilities**		
Standard #	**COM-001-0**	**Comments**
Title	Telecommunications	Okay
Purpose		Not sure that we need to include entities in Purpose.
Applicability		Not sure about inclusion of NERCNet
Requirements	*Conditions*	Interconnection is capitalized.
	Who?	Okay
	Shall do what?	R1.4 – should spell out applicability and extent for redundancy R2 – provide periodicity of testing R4 – cite communication protocol such as two-part communications R6 – probably doesn't belong here CESDT: R1 duplicated by COM-002 R1 R2 – 'special attention' R3 – 'provide a means' & 'ability to investigate'
	Result or Outcome	Missing
Measures		CESDT addressing but: • 4M for 6R • Still lacks measurability
To Do List	FERC NOPR o Include Measures and Levels of Non-Compliance; o Include generator operators and distribution provider as applicable entities; and o Include requirements for communication facilities for use during emergency situations. FERC staff report o Lacks adequacy, redundancy and routing requirements o Generation owners missing o Expect new standard in November V0 Industry Comments o Redundant with Policy 5A, R1 o Many players missing o Apply R1 to all but smallest entities VRF comments o R6 – administrative requirement	
Misc. Items		Compliance not specified but appears in CESDT version

Standard Review Form Project 2006-04 Back-up Facilities		
Standard #	**EOP-008-0**	**Comments**
Title	Plans for Loss of Control Center Functionality	Okay but could probably drop ‘Plans for’.
Purpose		Okay
Applicability		Isn’t the reliability entity the TSP and not the TO as per the FM?
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	Grammar error in R1.2
	Result or Outcome	Missing
Measures		Measure doesn’t define required evidence.
To Do List	FERC NOPR o Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability. o Provision for backup capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center. FERC staff report o Distinction between providing plans and proving capabilities o Independence from primary control center Regional Fill-in-the-Blank Team Comments o No comments V0 Industry Comments o How does staff know control center is lost? o How is backup control achieved? o Max. time to restore capabilities VRF comments o R1 - Not having a written plan does not directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading o R1.1 - Not having a written plan is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.	

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☐ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☐ No

   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments:

NORTH AMERICAN
ELECTRIC
RELIABILITY
COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731
www.nerc.com • 609-452-8060 (Voice) • 609-452-9550 (Fax)

November 6, 2006

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement
Comment Period Opens for two SARs;
Nomination Period Opens for two SAR Drafting Teams

The Standards Committee (SC) announces the following standards actions:

System Restoration and Blackstart SAR (November 6–December 5, 2006)

A new SAR, *System Restoration and Blackstart*, has been posted for a 30-day comment period from November 6 through December 5, 2006. The SAR calls for the modification of the following standards:

EOP-005 — System Restoration Plans

EOP-006 — Reliability Coordination – System Restoration

EOP-007 — Establish, Maintain, and Document a Regional Blackstart Capability Plan

EOP-009 — Documentation of Blackstart Generating Unit Test Results

This project involves upgrading the overall quality of the four standards; eliminating some gaps in the requirements; eliminating some ambiguity, and eliminating some 'fill-in-the-blank' components.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

Please use the comment form to provide comments on this SAR.

Back-up Facilities SAR (November 6–December 5, 2006)

A new SAR, *Back-up Facilities*, has been posted for a 30-day comment period from November 6 through December 5, 2006. The SAR calls for the modification of the following standards:

COM-001 — Telecommunications

EOP-008 — Plans for Loss of Control Center Functionality

This project involves upgrading the overall quality of the standards; adding specificity to the existing requirements; and eliminating redundancies with other standards.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Please use the comment form to provide comments on this SAR.

Nominations for System Restoration and Blackstart SAR Drafting Team (November 6–17, 2006)

The Standards Committee is seeking industry experts to serve on the System Restoration and Blackstart SAR Drafting Team. If you are interested in serving on this team, please complete this nomination form and return it to Richard Schneider (Richard.schneider@nerc.net) no later than November 17, 2006.

Nominations for Back-up Facilities SAR Drafting Team (November 6–17, 2006)

The Standards Committee is also seeking industry experts to serve on the Back-up Facilities SAR Drafting Team. If you are interested in serving on this team, please complete this nomination form and return it to Richard Schneider (Richard.schneider@nerc.net) no later than November 17, 2006.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

Standards Process Manager

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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:	Midwest ISO and Collaborating Stakeholders
Lead Contact:	**Terry Bilke**
Contact Organization:	**Midwest ISO**
Contact Segment:	**2**
Contact Telephone:	**317-571-8660**
Contact E-mail:	**tbilke@midwestiso.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Roderick Conwell	IPL	RFC	1
Jim Cyrulewski	JDRJC Associates		8
			0
			0
			0
			0
			0
			0

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☒ No

   Comments: Yes, there is a reliability-related need. While we expect the backup requirements for Reliability Coordinators be fairly standard, a one-size fits all approach may not be appropriate for all other entities. A small TOP or BA can perform many of their tasks with lower tech tools.

   The SAR needs additional definition. It should clearly define the bounds of the proposed standard.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☒ No

   Comments:
   The Brief Description provides no bounds on the scope of the study or project. Expected cost, duration, participants,etc.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments:
   This does not appear to be a yes-no question.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: TERRY DOERN		
Organization: BONNEVILLE POWER ADMINISTRATION - Transmission Business Lline		
Telephone: 360-418-2341		
E-mail: tldoern@bpa.gov		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☐ No

   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: Reliability Coordinators (RC's) are dependent on data from control areas and transmission owners. RCs also rely on control areas and transmission owners to control the transmission system via SCADA, generators using AGC or voice communications to others like generator operators. Therefore Control Areas and Transmission Owners must also have backup facilities to provide critical data and controls even after the loss of their own control center. Voice circuits to backup centers are also needed.

   Another problem area is Uninterruptible Power System or UPS. Failures of UPS are a leading factor in control center failure. Also, during a widespread blackout, UPS failures have occurred causing control center failure.

   Communications circuits are needed from backup facilities for control areas or transmission owners to critical Reliability centers and backup centers, critical adjacent utilities, and large generators.

   COM-001 does not address the need for voice or data communications circuits to generators. These circuits are required for AGC operation and also during emergencies including black start restoration. It may be addressed elsewhere in NERC standards.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)	
Name:	Martin Trence
Organization:	Xcel Energy - Northern States Power Company
Telephone:	(612) - 337 - 2152
E-mail:	martin.s.trence@xcelenergy.com

NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs, ISOs, Regional Reliability Councils
☒ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the ‘Standard Review Forms’ attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments: Need to address that communication facilities should be compatible. For primary communciations we are there just by evolution, but back-up communciations could easily be diverse, especially at the Reliability Coordinator level.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: Review training requirements to insure consistency and adequacy.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Will Franklin
Organization:	Entergy Services, Inc. System Planning & Operations
Telephone:	281-297-3594
E-mail:	wfrankl@entergy.com

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☐ No

   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments:
   COM-001-0/1
   R1 needs clarification for "adequate and reliable".
   R2 needs "and/or" clarification - is active monitoring satisfactory for compliance in lieu of testing? What does it mean to "alarm" a vital telecommunication facility? Is it the same as testing? Should a periodicity for testing be explicit? How is "vital" defined? How is "special attention" defined?
   R3 - what does "coordinate telecommunications" mean? Also, this requirement has no measure - should there be one?

   EOP-008-0
   Purpose - I have heard a lot of debate amongst industry members about whether a physical back up facility must exist or not, or if one just needs to have a 'plan'. This standard should make it explicitly clear as to whether a physical facility must exist. I believe it would be difficult to ensure the viability of a plan as required in R1.5 unless a physical facility existed.
   R1.8 - what constitutes "interim" provisions? The standard should consider stating the required time to make a back up center operational. PER-003-0 has a seemingly out of place requirement in its measures section (M1.2) about having NERC certified operators

at all times except for 4 hours for transition to a back up center. This might be a starting point.
VRFs - many appear to be administrative in nature, yet are rated as Medium. Please include in the review.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Brian Thumm	
Organization:	ITC Transmission	
Telephone:	248-374-7846	
E-mail:	bthumm@itctransco.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments: The requirements for backup facilities need more specificity in several areas.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments: The study of backup capabilities should be performed first, and then the SAR written to address the findings of the study.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments:

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: David Kiguel		
Organization: Hydro One Networks Inc.		
Telephone: 416-345-5313		
E-mail: David.Kiguel@HydroOne.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☒ No

   Comments: There is a need to upgrade requirements. The EOP and COM standards need to be rewritten to better reflect a requirement for backup control center in the event of the loss of the primary control center. The requirement for this backup control center should clearly articulate a minimum set of funtional requirements.

   However, we request clarification on this SAR before deciding if there is a reliability-related need to upgrade the requirements in this set of Standards. The SAR updates COM-001-0. The industry approved COM-001-1. What will happen to COM-001-1 if this SAR is approved? The Brief Description does not mention COM-001. Is that an oversight? Is this SAR only updating EOP-008? If this SAR updates COM-001, then what is that justification? The title of this SAR is Backup Facilities. Does that mean the updated COM-001 will apply only to backup facilities? Since the Interchange Authority (IA) should have at least an Area view, we suggest that the IA should be checked on. This assumes that the IA continues as a Functional Model Entity. This comment form's background information provides two solutions, 1) move the COM-001 requirements to other Standards or 2) update COM-001. We feel that decision is part of this SAR's scope. To fully explore moving COM-001 to other Standards, what are those other Standards? If moved, what happens to COM-001? We prefer that the other Standards reference COM-001 and that COM-001 be updated.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments: Hydro One submits that the Scope is too open ended and removal of the word "full" from the phrase "full backup facility" is suggested.

   Also, since Version 0, some in the industry have recommended that the NERCnet users be removed from the Applicability section as this is not an entity that is part of the NERC Funtional Model.
   We recommend that COM-001 R6 should not be a Reliability Requirement. R6 and Attachment 1 should be moved to a NERCnet procedure document. As written, the Requirements need better granularity so the industry can consistently measure compliance. The Requirements need to spell out the underlying assumptions such as "special attention" and the SAR's "shall do what" comment on R1.4.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: A study is referred to in the SAR. If a study is needed, what will be studied? What is in place today? What should be in place? If the study remains as part of the SAR, will the commenters decide what is required or will the requestor?

   Hydro One has concerns regarding COM-001. R1.2 which states "Entities shall provide adequate and reliable telecommunications facilities to ensure the exchange of interconnection and operating information." We are concerned that this might be somewhat ambiguous and recommends improved definition of terms like “adequate”, and perhaps some language that defines the parameters for the telecommunications facilities being provided. R3 says "Each RC, TOP and BA shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas." In consideration of the addition of compliance measures, we suggest that R3 be reviewed to confirm the objectives sought by this requirement. Further, that the language for R3 then be modified to more clearly convey the essence of the requirement. R4 says "Unless agreed to otherwise, each RC, Top and BA shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected BES. TOP and BA may use an alternate language for internal operations." We have concerns regarding how R4 would be monitored for compliance.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	Dede Subakti
Organization:	Midwest ISO Emergency Prepardness and Power System Restoration W.G.
Telephone:	(651) - 632 - 8400
E-mail:	dsubakti@midwetiso.org

NERC Region		Registered Ballot Body Segment
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs, ISOs, Regional Reliability Councils
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments: Standard EOP - 008 contains all the necessary elements pertaining to Back-Up Control Center requirements.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments: The scope of this project should not be limited to just revising two Standards due to directives from regulatory bodies, but should be flexible to meet industry needs, whether additional or fewer Standards are required to address Back-Up Control Center and Communication needs.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: Requirements for emergency communication should include the concept that the communication infrastructure be consistent between Reliability Coordinators, Transmission Operators, Balancing Authorities, and other applicable entities under the Functional Model.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Ed Davis	
Organization:	Entergy Services	
Telephone:	504-576-3029	
E-mail:	edavis@entergy.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☐ Yes

   ☒ No

   Comments:

   We believe there is not a reliability-related need to upgrade the requirements in this set of standards. We do agree these standards need to be reviewed and revised to make them better standards.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments:

   There are several issues within the proposed SAR that concern scope, timing and sequence.

   Please indicate in the scope why these two seemingly unrelated standards are being revised together.

   COM-001 R5 is the only part of COM-001 that is concerned with loss of telecommunications facilities. We suggest that the SAR contain an explicit statement that standard development be limited to revisions to COM-001 R5 only and no other part of COM-001 will be changed.

   The reference to the certification standards should be deleted as there are no approved certification standards, or the statement should be modified from - identify which of these ARE essential to reliable operations - to - identify which of these, PLUS OTHERS, MAY BE essential to reliable operations".

   Changes to these standards and requirements should be made based on the final rulemaking by FERC. They should not be made based on the NOPR and the SAR should so state.

   The SAR should specify the sequence of standard development activity especially since there is a study required. The SAR should indicate that a study is required and the study draft results will be circulated to the industry for comment and revision. Then, the SAR should state that revisions to EOP-008 and COM-001 R5 will be considered based on the results of that study.

We are concerned about the open-ended statements in the SAR. Those statements should be deleted or modified. The first is the statement that there are backup facility requirements in some other standard which should be moved into this standard. Those other standards should be specified in this SAR.

Additionally, the SAR contains the statement that - development may include other improvements to the standards deemed appropriate - should contain a statement that those other improvements will be limited to these two standards and approval of this SAR is not an open-ended approval to change standards and requirements other than EOP-008 and COM-001 R5 and back-up facility requriements that may be contained in the other standards specified in this SAR.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

☐ Yes

☐ No

Comments:

We have no additional revisions at this time.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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:	Southern Company		
Lead Contact:	**J. T. Wood**		
Contact Organization:	**Southern Company Services**		
Contact Segment:	**1**		
Contact Telephone:	**205-257-6238**		
Contact E-mail:	**jtwood@southernco.com**		
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***
Marc Butts	**Southern Company Services**	**SERC**	**1**
Roman Carter	**Southern Company Services**	**SERC**	**1**
Steve Corbin	**Southern Company Services**	**SERC**	**1**

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☐ No

   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments: It is recommended that a transition period of a couple of years be incorporated into the standard for being compliant with the new requirements. This will give the different entities time to get something constructed and maybe a new EMS system implemented before being compliant. In many cases there will be capital dollars that will need to be budgeted and spent and other major changes in order to be compliant.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Jerad Barnhart		
Organization: NSTAR Electric		
Telephone: 781 441 8209		
E-mail: jerad_barnhart@nstaronline.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

☒ Yes

☒ No

Comments:
Although NSTAR agrees there is a need to upgrade requirements, we believe the EOP and COM standard should to be rewritten to better reflect a requirement for backup control center in the event of the loss of the primary control center. The requirement for this backup control center should clearly articulate a minimum set of funtional requirements.

Also, we request clarification on this SAR before deciding if there is a reliability-related need to upgrade the requirements in this set of Standards. The SAR proposes to update COM-001-0. The industry approved COM-001-1. What will happen to COM-001-1 if this SAR is approved? The Brief Description does not mention COM-001. Is that an oversight? Is this SAR only updating EOP-008? If this SAR updates COM-001, then what is that justification? The title of this SAR is Backup Facilities. Does that mean the updated COM-001 will apply to only backup facilities? This comment form's background information provides two solutions, 1) move the COM-001 requirements to other Standards or 2) update COM-001. We feel that decision is part of this SAR's scope.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

☐ Yes

☒ No

Comments:
NSTAR believes the Scope is too open ended and removal of the word "full" from the phrase "full backup facility" is suggested.

Also, since Version 0, we have recommended that the NERCnet users be removed from the Applicability section. We cannot find NERCnet users in the Functional Model. We continue recommending that COM-001 R6 should not be a Reliability Requirement. R6 and Attachment 1 should be moved to a NERCnet procedure document. As written, the Requirements need better granularity so the industry can consistently measure compliance. The Requirements need to spell out the underlying assumptions such as "special attention" and the SAR's "shall do what" comment on R1.4.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

☒ Yes

☐ No

Comments:
A study is referred to in the SAR. If some study is needed, what will be studied? What is in place today? What should be in place? If the study remains as part of the SAR, will the commenters decide what is required or will the requestor?

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Jason Shaver	
Organization:	American Transmission Co.	
Telephone:	262 506 6885	
E-mail:	jshaver@atcllc.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments: The upgrade is needed in order to eliminate existing ambiguity and requirement redundancy.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments: ATC requests more detail on the scope and nature of the backup capability study identified in the "Brief Description" section of the SAR.
   1)What specifically is going to be asked in the study?
      a) Is the study going to include questions for both COM-001 and EOP-008?
   2) Who is going to oversee the development and results of the study?
      a) How are the results going to be incorporated into the revised Standards?
   3) What is the goal of the study?
   4) Why do the SAR's author(s) feel that a study needs to be performed before moving forward with improvements to the two standards?

   It's difficult from ATC's perspective to completely agree with the scope of the SAR when a major part of the effort (the study) is not defined.

   Second, the SAR identifies "new" Reliability Functions (Distribution Provider & Generator Operator) that may be subject to either one or both of these standards. Greater clarity needs to be provided as to how NERC will be expanding the Applicability of these standards. In other words, what existing requirements or new requirements would these entities be responsible for that they currently are not?

   Third, ATC requests that NERC consider expanding the applicability of these standards to the TSP and Market Operator functions. As the industry evolves the loss of these entities facilities may also have a major impact on system reliability.

   Fourth, the SAR states that there are back-up facility requirements in other standards that will be moved into this standard. That being the case, those standards with requirements that may be modified or "moved" as a result of this effort should be clearly identified under the "Related Standards" section of the Standard Authorization

Request Form. Currently this SAR has identified only the COM-001-0 and EOP-008-0 standards.

EOP-008-0

Per the Standards Review Form the Title of EOP-008 may be changed by dropping the words “Plans for” from the Standard’s title. If that is to be done, then it is also important to clarify the Purpose of this Standard to align with the title. Currenlty, the “Purpose” of the standard is to: "have a plan to continue reliability operations in the event its control center becomes inoperable.”

In the Standards Authorization Request Form, the Applicability section asks whether the reliability entity should be the TSP and not the TOP:

Question:
Isn’t the reliability entity the TSP and not the TO as per the FM?

As a TOP, ATC believes that the standard needs to continue to apply to TOPs. That being said, the standard may also need to be expanded to apply to the TSP function as well.

ATC believes that the Standard Authorization Request Form should clearly identify which entity is responsible for each requirement under the existing standard. Two specific requirements that would benefit from additional clarification include: R1.2 and R1.3 where the functional model responsibilities of the BA and TOP have been intermingled. Requirement 1.2 requires the RC, TOP and BA to have procedures for providing basic tie line control, inter-area schedules and hourly accounting for all schedules. This is required of all three entities but should apply to the BA and TSP/Interchange Authority. Likewise requirement 1.3 lumps requirements specific to three different functional entities under a single umbrella. Each of the components under the requirement should be broken out to the appropriate applicable entity. For example, TOPs should be responsible for the conrol of critical transmission facilities and the conrol of critical substation devices. BAs should be responsible for generation control, time and frequency control. Both entities should be responsible for loging significant power system events. The SAR needs to address this issue so that each entity is able to clearly identify and comply with those items under their purview of control and not be held responsible for those items outside thei control.

Similarly, any new requirements should clearly state who is responsible for performing that funtion.

COM-001-0

ATC believes that the Standard Authorization Request Form needs to be updated to reflect that the standard being worked on is COM-001-1 (Version 1) not COM-001-0 (Version 0). COM-001-0 is listed in the Standards Authorization Request Form even though COM-001-1 will become effective on January 1 2007.

The Applicability Section of this standard should be updated to remove “NERCNet User” from the list. A NERCNet user is not a defined term/entity under the NERC functional model and therefore, should not be used. NERC should take up any requirements for NERCNet users under a different forum (i.e. individual rules or agreements). In addition to removing the NERCNet user from the applicability section the standard, NERC should also remove any related requirements for this “entity”.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

☒ Yes

☐ No

Comments: ATC encourages the SC to select a wide range of individuals to work on these two standards. COM-001 will require the SDT to have some individuals with knowledge in telecommunication systems while EOP-008 requires individuals with an operations and facilities background.

The following comment is on the SAR’s form.

Section: Reliability Functions

Function: Market Operator

Existing language: Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.

ATC is concerned with the word “economic” being included in the description of Market Operator. The purpose of the SAR process is to develop reliability standards and the word economic being included in this description may cause problems/confusion down the road.

Suggested language:

Integrates energy, capacity, balancing, and transmission resources to achieve a reliability-constrained dispatch.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: James H. Sorrels, Jr.		
Organization: American Electric Power		
Telephone: (614) 716-2370		
E-mail: jhsorrels@AEP.com		
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments: Yes, EOP-008-0 is very weak in that it does not require the applicable entities to have a minimum defined level of backup capabilities nor to prove those backup capabilities. It is unacceptable that all that is required today is to have a set of plans.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☐ No

   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments: None identified at this time.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Jim Useldinger	
Organization:	Kansas City Power & Light	
Telephone:	816-654-1212	
E-mail:	jim.useldinger@kcpl.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments: SAR needs additional clarification.

   COM-001
   Generator Operators and Distirbition Operators should be included as applicable entities for telecommunications information.

   EOP-008
   The bulleted items under "FERC NOPR" are reliability-related issues and should be considered for changes to the standard EOP-008.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments: There are no bounds to the scope of the project.
   COM-001
   Agree with addition of measures, non-compliance, and addition of applicability with Generator Operators and Distribution Operators, but do not agree with any of the other specific comments.

   Agree with the proposed measures and non-compliance in COM-001 version 1 except for non-compliance 2.3.1 as a level 3 non-compliance. Recommend consideration be given to making this a level 2.

   The comments under "V0 Industry Comments" and "VRF Comments" are not specific enough to respond to.

   EOP-008
   Agree the plan should contain the provisions as suggested under bulleted items under "FERC NOPR" and do not agree with any of the other items. The comments under "V0 Industry Comments" are not specific enough to respond to. The comments under "VRF Comments" are editorial and should not be considered for any modification to the standard EOP-008.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments: This does not require a yes/no response. No other comments.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: Tennessee Valey Authority

Lead Contact: **Kathy Davis**

Contact Organization: **Transmission & Reliability Organization**

Contact Segment: **1**

Contact Telephone: **423-751-8023**

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
Sue Mangum Goins	TVA	SERC	1
Mark Creech	TVA	SERC	1
Earl Shockley	TVA	SERC	1
Jerry Landers	TVA	SERC	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments: We agree that there should be more detailed information in the Standards, but would prefer to see the results of the "study" before commenting futher.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments: Not enough detail to make an adequate determination.
   Why are we dealing with the Version 0 of COM-001 when version 1 is effective in January?

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments:

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Kevin Conway	
Organization:	PUD #2 of Grant County	
Telephone:	509-754-6639	
E-mail:	kconway@gcopud.org	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☐ Yes

   ☒ No

   Comments: I don't believe there is a reliability rated need per se, but there does seem to be a need to improve the standards to allow consistent evaluation of the back-up plans and facilities during audits and inspections.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☐ No

   Comments: The scope seems appropriate, but I am afraid that it may create an overly burdensome standard during the drafting process.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: It should be communicated clearly that any transition to a back up center should allow for the contunued normal operation of tasks and functions. The standard should be built on this concept, and should still allow for the type of tasks being done by the entitiy, and the level of effect that the entity has on the BES.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Michael Anthony	
Organization:	Progress Energy Carolinas	
Telephone:	919-546-5690	
E-mail:	mike.anthony@pgnmail.com	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☐ No

   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: We agree that the EOP-008 standard should require that Backup Control Centers to be functionally viable for managing long-term operation of the bulk electric system from the backup control center facility. With respect to COM-001, which this SAR puts in tandem with EOP-008, the requirement to maintain dedicated and redundant communications channels and plans for continued operations with loss of telecommunications should be required of LSEs and Generator Operators as well. This revision will require third party generators to provide for adequate communications to facilitate reliable operations for the BAs and TOPs.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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:	WECC Reliability Coordination Comments Work Group
Lead Contact:	**Nancy Bellows**
Contact Organization:	**WACM**
Contact Segment:	**2**
Contact Telephone:	**970-461-7246**
Contact E-mail:	**bellows@wapa.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Terry Baker	PRPA	WECC	2
Tom Botello	SCE	WECC	2
Richard Ellison	BPA	WECC	2
Mike Gentry	SRP	WECC	2
Robert Johnson	PSC	WECC	2
Greg Tillitson	CMRC	WECC	2

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☐ No

   Comments: Please define the acronym VRF that appears in the To Do List.
   While we agree with the scope of the project, we feel that clarification of terms is necessary to facilitate an improved standard.
   Inclusion of a requirement that all reliability coordinators have full backup control centers is included in first bullet of the To Do List. The meaning of "full" is unclear.
   The level of independence required in the second bullet of the To Do List needs to be specified. Does "independent" mean that separate RTU's and communication paths are needed for a backup facility, that there is no single point of failure shared between the two facilities, or does that term carry some other meaning?
   The second bullet of the To Do List specifies that the backup facility must be capable of operating for a prolonged period of time, but the meaning of "prolonged" remains unclear.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☒ No

   Comments:

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: Public Service Commission of South Carolina

Lead Contact: **Phil Riley**

Contact Organization: **Public Service Commission of South Carolina**

Contact Segment: **9**

Contact Telephone: **803-896-5154**

Contact E-mail: **philip.riley@psc.sc.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	Public Service Commission of SC	SERC	9
Elizabeth B. "Lib" Fleming	Public Service Commission of SC	SERC	9
G. O'Neal Hamilton	Public Service Commission of SC	SERC	9
John E. "Butch" Howard	Public Service Commission of SC	SERC	9
Randy Mitchell	Public Service Commission of SC	SERC	9
C. Robert "Bob" Moseley	Public Service Commission of SC	SERC	9
David A. Wright	Public Service Commission of SC	SERC	9

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☐ No

   Comments:

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments: None identified.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name: Robert Coish		
Organization: Manitoba Hydro		
Telephone: 204-487-5479		
E-mail: rgcoish@hydro.mb.ca		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☐ No

   Comments: Define "CESDT". This SAR says that a study of the backup capabilities that are needed to support reliable operations is required as part of this project. It is not clear what is the intended scope of this study. It might be helpful to the drafting team if the SAR indicated the expected time line to complete the work outlined in this SAR - perhaps by referring to the 2007-2009 work plan if timeframe is specified there.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☐ Yes

   ☐ No

   Comments: COM-001-0 and -1
   R1 what is "adequate", needs to be defined. "Interconnection and operating information", does this include data transfer as well as communications?
   R1.2 Should this not read: "Between the Reliability Coordinators, Transmission Operators, and Balancing Authorities." This sounds like one way communications between the RC and TO's and BA's.
   R2 - define "vital".
   R4 - "Unless agreed to otherwise" needs to be defined by whom?
   COM-001-1
   R1 - Missing the word "for" between "facilities the".

   EOP-008-0
   R1.5 - Need to define "periodic tests", this could vary from one company testing annually to another company testing every 5 years, to each periodic testing is met.
   This SAR should require that Violation Risk Factors be assigned to the requirements of COM-001 and EOP-008 and be included in the subsequently . Coordinate assignment of

VRF's with current ballot on Version 0 VRF and proposed VRF's for Version 1, as appropriate.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ron Falsetti	
Organization:	IESO	
Telephone:	905-855-6187	
E-mail:	ron.falsetti@ieso.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☒ No

   Comments: We agree that the 2 standards should be tightened up to meet reliability needs and FERC's request. However, we don't think the scope of this SAR is clearly defined (see comment on Q2 below). The SAR proposes to update COM-001-0 but the industry has already approved COM-001-1. What will happen to COM-001-1 if this SAR is approved? Please clarify.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☐ Yes

   ☒ No

   Comments: (1) The Brief Description does not provide any bounds on the work that is envisioned. For example, it was mentioned that "there are backup requirements in some other standards", which standards are they? Further, there is no elaboration on what "study" will be conducted, which leaves the industry to speculate what study and its scope are being pursued, and how its outcomes may affect the standards. The industry is left without any clue to offer comments on this particular issue.

   (2) If COM-001-1 is to be revised, then we offer the following suggestions:

   (i) Since Version 0, we have recommended that the NERCnet users be removed from the Applicability section. We cannot find NERCnet users in the Functional Model. The Requirements need to spell out the underlying assumptions such as "special attention" and the SAR's "shall do what" comment on R1.4.

   (ii) R1.2:
   Entities shall provide adequate and reliable telecommunications facilities to ensure the exchange of interconnection and operating information.

   The IESO is concerned that this might be somewhat ambiguous and recommends improved definition of terms like "adequate", and perhaps some language that defines the parameters for the telecommunications facilities being provided.

   (iii) R3:

Each RC, TOP and BA shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.

In consideration of the addition of compliance measures, we suggest that R3 be reviewed to confirm the objectives sought by this requirement. Further, the language for R3 needs to be modified to more clearly convey the essence of the requirement.

(iV) R4:
Unless agreed to otherwise, each RC, Top and BA shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected BES. TOP and BA may use an alternate language for internal operations.

We have concerns regarding how R4 would be monitored for compliance.

(v) R6:
Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy".

We recommend R6 be removed from the COM-001 requirements as it is considered general terms for completing the NERCnet application.

(vi) Lastly, we question whether or not COM-001 should remain as a standard since most of the requirements were mapped to existing documents (some with the exact same language as the requirement), while requirements such as R1.2, R3 and R4 contain ambiguous language leaving margin for being misinterpreted.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

☒ Yes

☐ No

Comments: (1) Without knowing the bounds of the work and the purpose and expected outcomes of the "study", we are unable to offer further comments but feel uncomfortable to be asked to support this SAR to start standard development work.

(2) Since some transmission owning entities may not register as a TOP but may have local control tasks assigned to it by the TOP, the Transmission Owner should also be included as an Applicable entity for both EOP-008 and COM-001.

Please use this form to submit comments on the proposed SAR for Back-up Facilities. Comments must be submitted by **December 5, 2006.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Back-up Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at Ed.Dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs, Regional Reliability Councils
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: Salt River Project

Lead Contact: **Mike Gentry**

Contact Organization: **Transmission & Generation Operations**

Contact Segment: **1**

Contact Telephone: **602-236-6408**

Contact E-mail: **mlgentry@srp.net**

Additional Member Name	Additional Member Organization	Region*	Segment*
Gary Strickler	Computer Applications	WECC	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

This project involves upgrading the requirements in these two standards:

COM-001: Telecommunications
EOP-008: Plans for Loss of Control Center Functionality

There are many stakeholder comments about this set of standards that need to be resolved. For example, the requirements in EOP-008 need additional specificity — for example R1 requires entities to have a contingency plan, but does not require that entities have the facilities identified in the plan. There are back-up facility requirements in several other standards (including COM-001), and this SAR would move all those requirements into either the certification standards or in this revised standard.

The *Federal Energy Regulatory Commission's (FERC's) October 20, 2006 Notice of Proposed Rulemaking (NOPR) on Mandatory Standards for the Bulk-Power System* included language that suggested the following changes should be made to EOP-008, and industry discussion is needed on these proposed changes:

- Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.
- Provision for back-up capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

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. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

   ☒ Yes

   ☐ No

   Comments: Admittedly, there are some "holes" in the current version.

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

   ☒ Yes

   ☐ No

   Comments: The scope appears reasonable in order to provide measurable reauirements. Please define the acronym "VRF" that appears as comments in the To Do List.

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

   ☒ Yes

   ☐ No

   Comments: Regarding R1.5, where it talks of ". . . conducting periodic tests, at least annually . . ." I would suggest monthly instead, but this has effects outside of just CA.

   Also, the NERC proposed changes talk of " . . . (2) be capable of operating for a prolonged period of time; . . ." And we have a 10 year schedule to add all of our existing RTUs to TCC. I assume that if TCC became our only dispatch center, would we accelerate this?

Consideration of Comments on 1st Draft of Backup Facilities SAR

The Backup Facilities SAR Drafting Team thanks all commenters who submitted comments on Draft 1of the Backup Facilities SAR. This SAR was posted for a 30-day public comment period from November 6 through December 5, 2006. The Backup Facilities SAR Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 23 sets of comments, including comments from more than 60 different people from more than 25 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based upon industry comments, the SAR DT determined that there is a reliability requirement for this SAR on back-up capabilities. Most of the comments were associated with points of clarification.

The questions/concerns raised by stakeholders centered around 8 areas:

- The study of backup capabilities referenced in the SAR — the drafting team modified the SAR to clarify that the work of the OC Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008
- The inclusion of the 'COM' standards in the SAR — the drafting team removed COM-001 from the list of standards to be addressed with this project
- References to backup capabilities in other Reliability Standards — the drafting team modified the SAR to clarify that there 'may' be some requirements for backup capabilities in other Reliability Standards and added IRO-002 to the list of related standards because it does contain some backup facility requirements
- Information in Appendix B – the drafting team modified the SAR to clarify that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard.
- The inclusion of Distribution Provider and Generation Operator in the SAR — the drafting team modified to SAR to remove the Distribution Provider and Generator Operator as responsible entities.
- The relationship between Transmission Operators and other functions such as Transmission Owners and Market Operators as it relates to applicability in this SAR — the drafting team did add clarifying language to the SAR to indicate that the standard will apply to apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System; while Transmission Owners were added to the list of applicable functions, the Market Operator was not added to the SAR.
- The specification of standard requirements and the entities to which they would apply — the drafting team revised the SAR to indicate that the standard will be applicable to the Reliability Coordinator, Balancing Authority or Transmission Operator and to any entity performing reliability functions as a result of delegation of tasks from those entities.   .
- The lack of clarity and conceptual bounds with regards to the scope of the SAR — the drafting team added more specificity to clarify that the objective of the standard is to emphasize the continuation of functionality needed for reliable system operation regardless of the manner in which it is achieved.

The SAR Drafting Team responded to each of these areas with specificity appropriate for the SAR drafting stage. The intent of the SAR Drafting Team is to provide the conceptual boundaries around Backup Capability, while providing ample flexibility to the Standard Drafting Team to develop clear and crisp reliability standards with respect to backup capability. We believe that the revisions made to the SAR provide this flexibility and clarity.

Based on the comments received, the drafting team is re-posting the SAR for a second comment period.

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 SAR can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Backup_Facilities.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.

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	James Sorrels	American Electric Power	✓				✓	✓				
2.	Jason Shaver	American Transmission Company	✓									
3.	Terry Doern	Bonneville Power Administration	✓									
4.	Edward Davis	Entergy Services, Inc.	✓									
5.	Will Franklin	Entergy Services, Inc.						✓				
6.	David Kiguel	Hydro One Networks Inc.	✓									
7.	Ron Falsetti	Independent Electricity System Operator		✓								
8.	Roderick Conwell	IPL	✓									
9.	Charles Yeung (SPP)	IRC Standards Review Committee		✓								
10.	Tom Bowe (PJM)	IRC Standards Review Committee		✓								
11.	Mike Calimano (NYISO)	IRC Standards Review Committee		✓								
12.	Ron Falsetti (IESO)	IRC Standards Review Committee		✓								
13.	Matt Goldberg (ISONE)	IRC Standards Review Committee		✓								
14.	Brent Kingsford (CAISO)	IRC Standards Review Committee		✓								
15.	Anita Lee (AESO)	IRC Standards Review Committee		✓								
16.	Steve Myers (ERCOT)	IRC Standards Review Committee		✓								
17.	Bill Phillips (MISO)	IRC Standards Review Committee		✓								
18.	Kathleen Goodman	ISO New England		✓								
19.	Brian Thumm	ITC Transmission	✓									
20.	Jim Cyrulewski	JDRJC Associates								✓		
21.	Jim Useldinger	Kansas City Power & Light Company	✓									
22.	Robert Coish	Manitoba Hydro	✓		✓		✓	✓				
23.	Dede Subakti	Midwest ISO, Inc.		✓								
24.	Terry Bilke	Midwest ISO, Inc.		✓								
25.	Guy Zito (NPCC)	NPCC CP9 Reliability Standards Working Group		✓								
26.	Ralph Rufrano (NYPA)	NPCC CP9 Reliability Standards Working Group	✓									
27.	Kathleen Goodman (ISONE)	NPCC CP9 Reliability Standards Working Group		✓								
28.	Bill Shemley (ISONE)	NPCC CP9 Reliability Standards Working Group		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
29.	Greg Campoli (NYISO)	NPCC CP9 Reliability Standards Working Group		✓								
30.	Roger Champagne (TEHQ)	NPCC CP9 Reliability Standards Working Group	✓									
31.	David Kiguel (Hydro One)	NPCC CP9 Reliability Standards Working Group	✓									
32.	Herbert Schrayshuen (NGrid)	NPCC CP9 Reliability Standards Working Group	✓									
33.	Donald Nelson (MA Dept. of Tele and Energy)	NPCC CP9 Reliability Standards Working Group									✓	
34.	Ed Thompson (ConEd)	NPCC CP9 Reliability Standards Working Group	✓									
35.	Ron Falsetti (IESO)	NPCC CP9 Reliability Standards Working Group		✓								
36.	Alan Adamson (NYSRC)	NPCC CP9 Reliability Standards Working Group										✓
37.	Jerad Barnhart	NSTAR Electric	✓									
38.	Michael Anthony	Progress Energy Carolinas	✓									
39.	Phil Riley	Public Service Commission of SC									✓	
40.	Mignon L. Clyburn	Public Service Commission of SC									✓	
41.	Elizabeth B. Fleming	Public Service Commission of SC									✓	
42.	G. O'Neal Hamilton	Public Service Commission of SC									✓	
43.	John E. Howard	Public Service Commission of SC									✓	
44.	Randy Mitchell	Public Service Commission of SC									✓	
45.	C. Robert Moseley	Public Service Commission of SC									✓	
46.	David A. Wright	Public Service Commission of SC									✓	
47.	Kevin Conway	PUD #2 of Grant County				✓						
48.	Mike Gentry	Salt River Project	✓									
49.	Gary Strickler	Salt River Project	✓									
50.	J.T. Wood	Southern Company Services, Inc.	✓									
51.	Marc Butts	Southern Company Services, Inc.	✓									
52.	Roman Carter	Southern Company Services, Inc.	✓									
53.	Steve Corbin	Southern Company Services, Inc.	✓									
54.	Kathy Davis	Tennessee Valley Authority	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
55.	Sue Mangum Goins	Tennessee Valley Authority	✓									
56.	Mark Creech	Tennessee Valley Authority	✓									
57.	Earl Shockley	Tennessee Valley Authority	✓									
58.	Jerry Landers	Tennessee Valley Authority	✓									
59.	Nancy Bellows (WACM)	WECC Reliability Coordination Comments Work Group		✓								
60.	Terry Baker (PRPA)	WECC Reliability Coordination Comments Work Group		✓								
61.	Tom Botello (SCE)	WECC Reliability Coordination Comments Work Group		✓								
62.	Richard Ellison (BPA)	WECC Reliability Coordination Comments Work Group		✓								
63.	Mike Gentry (SRP)	WECC Reliability Coordination Comments Work Group		✓								
64.	Robert Johnson (PSC)	WECC Reliability Coordination Comments Work Group		✓								
65.	Greg Tillitson (CMRC)	WECC Reliability Coordination Comments Work Group		✓								
66.	Martin Trence	Xcel Energy – NSP	✓									

Index to Questions, Comments, and Responses

1. **Do you believe that there is a reliability-related need to upgrade the requirements in this set of standards?**

Summary Consideration:
Most commenters indicated that they do believe that there is a reliability-related need to upgrade the requirements in this set of standards.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Entergy Services, Inc.		☑	We believe there is not a reliability-related need to upgrade the requirements in this set of standards. We do agree these standards need to be reviewed and revised to make them better standards.
Response: The SAR Drafting Team recognizes that whether there is a reliability-related need is subjective and open to interpretation of the question, but does agree with the commenters' conclusion that the standards need to be upgraded and improved.			
PUD #2 of Grant County		☑	I don't believe there is a reliability rated need per se, but there does seem to be a need to improve the standards to allow consistent evaluation of the back-up plans and facilities during audits and inspections.
Response: The SAR Drafting Team recognizes that whether there is a reliability-related need is subjective and open to interpretation of the question, but does agree with the commenters' conclusion that the standards need to be upgraded and improved.			
Hydro One Networks Inc.	☑	☑	There is a need to upgrade requirements. The EOP and COM standards need to be rewritten to better reflect a requirement for backup control center in the event of the loss of the primary control center. The requirement for this backup control center should clearly articulate a minimum set of funtional requirements. However, we request clarification on this SAR before deciding if there is a reliability-related need to upgrade the requirements in this set of Standards. The SAR updates COM-001-0. The industry approved COM-001-1. What will happen to COM-001-1 if this SAR is approved? The Brief Description does not mention COM-001. Is that an oversight? Is this SAR only updating EOP-008? If this SAR updates COM-001, then what is that justification? The title of this SAR is Backup Facilities. Does that mean the updated COM-001 will apply only to backup facilities? Since the Interchange Authority (IA) should have at least an Area view, we suggest that the IA should be checked on. This assumes that the IA continues as a Functional Model Entity. This comment form's background information provides two solutions, 1) move the COM-001 requirements to other Standards or 2) update COM-001. We feel that decision is part of this SAR's scope. To fully explore moving COM-001 to other Standards, what are those other Standards? If moved, what happens to COM-001? We prefer that the other Standards reference COM-001 and that COM-001 be updated.
Response: The SAR Drafting Team agrees that the standard needs to be upgraded. The reference in the draft SAR to COM-001-0 was an oversight. However, the SAR Drafting Team agrees the current wording in the "Brief Description" section does not address COM-001 and after discussion has determined to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.			
NPCC CP9 Reliability Standards Working Group	☑	☑	NPCC Participating Members agree there is a need to upgrade requirements. We believe the EOP and COM standard needs to be rewritten to better reflect a requirement for backup

Question #1			
Commenter	**Yes**	**No**	**Comment**
			control center in the event of the loss of the primary control center. The requirement for this backup control center should clearly articulate a minimum set of functional requirements. Also, NPCC participating members request clarification on this SAR before deciding if there is a reliability-related need to upgrade the requirements in this set of Standards. The SAR updates COM-001-0. The industry approved COM-001-1. What will happen to COM-001-1 if this SAR is approved? The Brief Description does not mention COM-001. Is that an oversight? Is this SAR only updating EOP-008? If this SAR updates COM-001, then what is that justification? The title of this SAR is Backup Facilities. Does that mean the updated COM-001 will apply to only backup facilities? Since the Interchange Authority (IA) should have at least an Area view, we suggest that the IA should be checked on. This assumes that the IA continues as a Functional Model Entity. This comment form's background information provides two solutions, 1) move the COM-001 requirements to other Standards or 2) update COM-001. We feel that decision is part of this SAR's scope. To fully explore moving COM-001 to other Standards, what are those other Standards? If moved, what happens to COM-001? We prefer that the other Standards reference COM-001 and that COM-001 be updated.
Response: The SAR Drafting Team agrees that the standard needs to be upgraded. The reference in the draft SAR to COM-001-0 was an oversight. However, the SAR Drafting Team agrees the current wording in the "Brief Description" section does not address COM-001 and after discussion has determined to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.			
NSTAR Electric ISO New England	☑	☑	Although NSTAR (ISO NE) agrees there is a need to upgrade requirements, we believe the EOP and COM standard should to be rewritten to better reflect a requirement for backup control center in the event of the loss of the primary control center. The requirement for this backup control center should clearly articulate a minimum set of functional requirements. Also, we request clarification on this SAR before deciding if there is a reliability-related need to upgrade the requirements in this set of Standards. The SAR proposes to update COM-001-0. The industry approved COM-001-1. What will happen to COM-001-1 if this SAR is approved? The Brief Description does not mention COM-001. Is that an oversight? Is this SAR only updating EOP-008? If this SAR updates COM-001, then what is that justification? The title of this SAR is Backup Facilities. Does that mean the updated COM-001 will apply to only backup facilities? This comment form's background information provides two solutions, 1) move the COM-001 requirements to other Standards or 2) update COM-001. We feel that decision is part of this SAR's scope.
Response: The SAR Drafting Team agrees that the standard needs to be upgraded. The reference in the draft SAR to COM-001-0 was an oversight. However, the SAR Drafting Team agrees the current wording in the "Brief Description" section does not address COM-001 and after discussion has determined to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
MISO, IPL, JDRJC Associates	☑	☑	Yes, there is a reliability-related need. While we expect the backup requirements for Reliability Coordinators be fairly standard, a one-size fits all approach may not be appropriate for all other entities. A small TOP or BA can perform many of their tasks with lower tech tools. The SAR needs additional definition. It should clearly define the bounds of the proposed standard.
Response: The SAR Drafting Team agrees with the comment that a "one-size fits all approach may not be appropriate" and has reflected that in the revised SAR.			
Independent Electricity System Operator	☑		We agree that the 2 standards should be tightened up to meet reliability needs and FERC's request. However, we don't think the scope of this SAR is clearly defined (see comment on Q2 below). The SAR proposes to update COM-001-0 but the industry has already approved COM-001-1. What will happen to COM-001-1 if this SAR is approved? Please clarify.
Response: The SAR Drafting Team agrees that the standard needs to be upgraded. The reference in the draft SAR to COM-001-0 was an oversight. However, the SAR Drafting Team agrees the current wording in the "Brief Description" section does not address COM-001 and after discussion has determined to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR. The SAR DT discussed the applicability of the IA to this SAR and decided that the IA was not an applicable entity in this regard. We believe that the true responsible entities are the RC, BA and TOP. The SAR Drafting Team agrees with the comment that a "one-size fits all approach may not be appropriate" and has reflected that in the revised SAR.			
ITC Transmission	☑		The requirements for backup facilities need more specificity in several areas.
Response: The SAR Drafting Team agrees with the comments concerning the need for upgrades to the standard.			
American Transmission Company	☑		The upgrade is needed in order to eliminate existing ambiguity and requirement redundancy.
Response: The SAR Drafting Team agrees with the comments concerning the need for upgrades to the standard.			
American Electric Power	☑		Yes, EOP-008-0 is very weak in that it does not require the applicable entities to have a minimum defined level of backup capabilities nor to prove those backup capabilities. It is unacceptable that all that is required today is to have a set of plans.
Response: The SAR Drafting Team agrees with the comments concerning the need for upgrades to the standard.			
Salt River Project	☑		Admittedly, there are some "holes" in the current version.
Response: The SAR Drafting Team agrees with the comment that there are some "holes" in the current version.			
Kansas City Power & Light Company	☑		SAR needs additional clarification. COM-001 Generator Operators and Distiribition Operators should be included as applicable entities for

Question #1			
Commenter	**Yes**	**No**	**Comment**
			telecommunications information. EOP-008 The bulleted items under "FERC NOPR" are reliability-related issues and should be considered for changes to the standard EOP-008.
Response: The SAR Drafting Team agrees the SAR needs additional clarification and believes the specific matters raised by this commenter with regard to EOP-008 are within the scope of this SAR as revised. After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.			
Tennessee Valley Authority	☑		We agree that there should be more detailed information in the Standards, but would prefer to see the results of the "study" before commenting futher.
Response: The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing.			
Midwest ISO, Inc.	☑		Standard EOP - 008 contains all the necessary elements pertaining to Back-Up Control Center requirements.
Response: The SAR Drafting Team agrees that the current EOP-008 standard contains many of the necessary elements, but believes there are several areas within the standard that need to be upgraded such as requiring capability as opposed to simply having a plan.			
Bonneville Power Administration	☑		
Xcel Energy – NSP	☑		
IRC Standards Review Committee	☑		
Southern Company Services, Inc.	☑		
Entergy Services, Inc.	☑		
Progress Energy Carolinas	☑		
WECC Reliability Coordination Comments Work Group	☑		
Public Service Commission of SC	☑		
Manitoba Hydro	☑		

2. **Do you agree with the scope of the proposed project? (The scope includes all the items noted on the 'Standard Review Forms' attached to the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.)**

Summary Consideration: Most commenters disagreed with the scope of the proposed project and, based on stakeholder comments, the drafting team made the following changes to the SAR:

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process. It should not be considered to contain mandatory changes to the standard.
- Removed COM-001 from the list of standards addressed by the SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.
- Removed references to certification standards from the SAR
- Clarified that the work of the Operating Committee's Backup Control Center Task Force study will be used as an input to the development of the standard's requirements. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing.

Question #2			
Commenter	**Yes**	**No**	**Comment**
ITC Transmission		☑	The study of backup capabilities should be performed first, and then the SAR written to address the findings of the study.
Response: The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing.			
IRC Standards Review Committee		☑	The SRC would suggest that the SAR be clear that it will be a complete review of the subject requirements: to include the addition, deletion and modification of requirements as agreed to by public consensus and not be limited to the "TO DO LIST" identified in this draft.
Response: The SAR DT agrees that the needs of the entire industry will be reviewed and considered rather than only addressing perceived deficiencies.			
Midwest ISO, Inc.		☑	The scope of this project should not be limited to just revising two Standards due to directives from regulatory bodies, but should be flexible to meet industry needs, whether additional or fewer Standards are required to address Back-Up Control Center and Communication needs.
Response: The SAR DT agrees that the needs of the entire industry will be reviewed and considered rather than only addressing perceived deficiencies.			
Entergy Services, Inc.		☑	There are several issues within the proposed SAR that concern scope, timing and sequence. Please indicate in the scope why these two seemingly unrelated standards are being revised together. COM-001 R5 is the only part of COM-001 that is concerned with loss of telecommunications facilities. We suggest that the SAR contain an explicit statement that standard development be limited to revisions to COM-001 R5 only and no other part of COM-001 will be changed.

Question #2			
Commenter	**Yes**	**No**	**Comment**
			The reference to the certification standards should be deleted as there are no approved certification standards, or the statement should be modified from - identify which of these ARE essential to reliable operations - to - identify which of these, PLUS OTHERS, MAY BE essential to reliable operations". Changes to these standards and requirements should be made based on the final rulemaking by FERC. They should not be made based on the NOPR and the SAR should so state. The SAR should specify the sequence of standard development activity especially since there is a study required. The SAR should indicate that a study is required and the study draft results will be circulated to the industry for comment and revision. Then, the SAR should state that revisions to EOP-008 and COM-001 R5 will be considered based on the results of that study. We are concerned about the open-ended statements in the SAR. Those statements should be deleted or modified. The first is the statement that there are backup facility requirements in some other standard which should be moved into this standard. Those other standards should be specified in this SAR. Additionally, the SAR contains the statement that - development may include other improvements to the standards deemed appropriate - should contain a statement that those other improvements will be limited to these two standards and approval of this SAR is not an open-ended approval to change standards and requirements other than EOP-008 and COM-001 R5 and back-up facility requriements that may be contained in the other standards specified in this SAR.

Response:

After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.

The SAR DT agrees with the comment on certification standards and have removed this reference from the SAR.

The NOPR must be taken into consideration when drafting this Standard since it is occurring now. When the final FERC ruling is issued, changes may be necessary if it differs significantly from the NOPR input.

The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing.

The SAR DT will review whether the backup requirements in other Standards will need to be consolidated into this one. The BFSDT will only consider what requirements are necessary for reliable system operations.

Question #2			
Commenter	**Yes**	**No**	**Comment**
The SAR DT does not intend to change other Standards. If appropriate, the BFSDT will relocate backup requirements from other Standards and include them in this Standard. The other Standards could then be updated to remove the redundant requirements.			
NPCC CP9 Reliability Standards Working Group NSTAR Electric Hydro One Networks Inc.		☑	NPCC participating members (ISO-NE) (NSTAR) (Hydro One Networks) believe the Scope is too open ended and removal of the word "full" from the phrase "full backup facility" would be suggested. Also, since Version 0, NPCC participating members have recommended that the NERCnet users be removed from the Applicability section. We cannot find NERCnet users in the Functional Model. We continue recommending that COM-001 R6 should not be a Reliability Requirement. R6 and Attachment 1 should be moved to a NERCnet procedure document. As written, the Requirements need better granularity so the industry can consistently measure compliance. The Requirements need to spell out the underlying assumptions such as "special attention" and the SAR's "shall do what" comment on R1.4.
Response: The word "Full" only exists in Appendix B that is now listed as consideration only and not mandatory changes. It is possible (as pointed in several comments) that alternatives may exist to meet the requirements without requiring a "full" backup or complete duplication of a Primary Control Center. After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.			
American Transmission Company		☑	ATC requests more detail on the scope and nature of the backup capability study identified in the "Brief Description" section of the SAR. 1)What specifically is going to be asked in the study? a) Is the study going to include questions for both COM-001 and EOP-008? 2) Who is going to oversee the development and results of the study? a) How are the results going to be incorporated into the revised Standards? 3) What is the goal of the study? 4) Why do the SAR's author(s) feel that a study needs to be performed before moving forward with improvements to the two standards? It's difficult from ATC's perspective to completely agree with the scope of the SAR when a major part of the effort (the study) is not defined. Second, the SAR identifies "new" Reliability Functions (Distribution Provider & Generator Operator) that may be subject to either one or both of these standards. Greater clarity needs to be provided as to how NERC will be expanding the Applicability of these standards. In other words, what existing requirements or new requirements would these entities be responsible for that they currently are not? Third, ATC requests that NERC consider expanding the applicability of these standards to the TSP and Market Operator functions. As the industry evolves the loss of these entities facilities may also have a major impact on system reliability.

Question #2			
Commenter	**Yes**	**No**	**Comment**
			Fourth, the SAR states that there are back-up facility requirements in other standards that will be moved into this standard. That being the case, those standards with requirements that may be modified or "moved" as a result of this effort should be clearly identified under the "Related Standards" section of the Standard Authorization Request Form. Currently this SAR has identified only the COM-001-0 and EOP-008-0 standards. EOP-008-0 Per the Standards Review Form the Title of EOP-008 may be changed by dropping the words “Plans for” from the Standard’s title. If that is to be done, then it is also important to clarify the Purpose of this Standard to align with the title. Currenlty, the “Purpose” of the standard is to: "have a plan to continue reliability operations in the event its control center becomes inoperable.” In the Standards Authorization Request Form, the Applicability section asks whether the reliability entity should be the TSP and not the TOP: Question: Isn’t the reliability entity the TSP and not the TO as per the FM? As a TOP, ATC believes that the standard needs to continue to apply to TOPs. That being said, the standard may also need to be expanded to apply to the TSP function as well. ATC believes that the Standard Authorization Request Form should clearly identify which entity is responsible for each requirement under the existing standard. Two specific requirements that would benefit from additional clarification include: R1.2 and R1.3 where the functional model responsibilities of the BA and TOP have been intermingled. Requirement 1.2 requires the RC, TOP and BA to have procedures for providing basic tie line control, inter-area schedules and hourly accounting for all schedules. This is required of all three entities but should apply to the BA and TSP/Interchange Authority. Likewise requirement 1.3 lumps requirements specific to three different functional entities under a single umbrella. Each of the components under the requirement should be broken out to the appropriate applicable entity. For example, TOPs should be responsible for the conrol of critical transmission facilities and the conrol of critical substation devices. BAs should be responsible for generation control, time and frequency control. Both entities should be responsible for loging significant power system events. The SAR needs to address this issue so that each entity is able to clearly identify and comply with those items under their purview of control and not be held responsible for those items outside thei control. Similarly, any new requirements should clearly state who is responsible for performing that funtion.

Question #2			
Commenter	**Yes**	**No**	**Comment**
			COM-001-0 ATC believes that the Standard Authorization Request Form needs to be updated to reflect that the standard being worked on is COM-001-1 (Version 1) not COM-001-0 (Version 0). COM-001-0 is listed in the Standards Authorization Request Form even though COM-001-1 will become effective on January 1 2007. The Applicability Section of this standard should be updated to remove “NERCNet User” from the list. A NERCNet user is not a defined term/entity under the NERC functional model and therefore, should not be used. NERC should take up any requirements for NERCNet users under a different forum (i.e. individual rules or agreements). In addition to removing the NERCNet user from the applicability section the standard, NERC should also remove any related requirements for this “entity”.
Response: The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing. Generator Operator & Distribution Provider functions are contained in the NERC Functional Model but were only pertinent to COM-001 as per the FERC NOPR referenced in Appendix B. After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR. The SAR DT discussed the applicability of the TSP and MP to this SAR and decided that they were not applicable entities in this regard. We believe that the coverage provided by the RC, BA and TOP should be sufficient to cover the need for control center backup. The SAR DT agrees that any associated standards that may be affected by this project will be identified in the SAR. EOP-008: 1) The SAR DT agrees that the SDT should consider changing the title and purpose of EOP-008 2) The SAR DT agrees that individual requirements should be associated with the responsible entity.			
Kansas City Power & Light Company		☑	There are no bounds to the scope of the project. COM-001 Agree with addition of measures, non-compliance, and addition of applicability with Generator Operators and Distribution Operators, but do not agree with any of the other specific comments. Agree with the proposed measures and non-compliance in COM-001 version 1 except for non-compliance 2.3.1 as a level 3 non-compliance. Recommend consideration be given to making this a level 2.

Question #2			
Commenter	Yes	No	Comment
			The comments under "V0 Industry Comments" and "VRF Comments" are not specific enough to respond to. EOP-008 Agree the plan should contain the provisions as suggested under bulleted items under "FERC NOPR" and do not agree with any of the other items. The comments under "V0 Industry Comments" are not specific enough to respond to. The comments under "VRF Comments" are editorial and should not be considered for any modification to the standard EOP-008.
Response: The SAR DT has made changes to the content of the SAR that are believed to have clarified the scope of the project. After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR. Appendix B is an informative attachment that contains material for consideration in the standards revision process. It should not be considered to contain mandatory changes to the standard.			
Tennessee Valley Authority		☑	Not enough detail to make an adequate determination. Why are we dealing with the Version 0 of COM-001 when version 1 is effective in January?
Response: The SAR DT has made changes to the content of the SAR that are believed to have clarified the scope of the project. After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.			
Xcel Energy – NSP		☑	Need to address that communication facilities should be compatible. For primary communciations we are there just by evolution, but back-up communciations could easily be diverse, especially at the Reliability Coordinator level.
Response: Any considerations for compatibility of communications facilities should be considered by the SDT We believe that the SAR as revised has sufficient flexibility to cover this issue.			
Independent Electricity System Operator		☑	(1) The Brief Description does not provide any bounds on the work that is envisioned. For example, it was mentioned that "there are backup requirements in some other standards", which standards are they? Further, there is no elaboration on what "study" will be conducted, which leaves the industry to speculate what study and its scope are being pursued, and how its outcomes may affect the standards. The industry is left without any clue to offer comments on this particular issue. (2) If COM-001-1 is to be revised, then we offer the following suggestions: (i) Since Version 0, we have recommended that the NERCnet users be removed from the Applicability

Question #2			
Commenter	**Yes**	**No**	**Comment**
			section. We cannot find NERCnet users in the Functional Model. The Requirements need to spell out the underlying assumptions such as "special attention" and the SAR's "shall do what" comment on R1.4. (ii) R1.2: Entities shall provide adequate and reliable telecommunications facilities to ensure the exchange of interconnection and operating information. The IESO is concerned that this might be somewhat ambiguous and recommends improved definition of terms like "adequate", and perhaps some language that defines the parameters for the telecommunications facilities being provided. (iii) R3: Each RC, TOP and BA shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas. In consideration of the addition of compliance measures, we suggest that R3 be reviewed to confirm the objectives sought by this requirement. Further, the language for R3 needs to be modified to more clearly convey the essence of the requirement. (iV) R4: Unless agreed to otherwise, each RC, Top and BA shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected BES. TOP and BA may use an alternate language for internal operations. We have concerns regarding how R4 would be monitored for compliance. (v) R6: Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy". We recommend R6 be removed from the COM-001 requirements as it is considered general terms for completing the NERCnet application. (vi) Lastly, we question whether or not COM-001 should remain as a standard since most of the requirements were mapped to existing documents (some with the exact same language as the requirement), while requirements such as R1.2, R3 and R4 contain ambiguous language leaving margin for being misinterpreted.

<table>
<tr><th colspan="4">Question #2</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">Response:
The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing.

The SAR DT agrees that any associated standards that may be affected by this project will be identified in the SAR.

After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.</td></tr>
<tr><td>MISO, IPL, JDRJC Associates</td><td>☑</td><td>☑</td><td>The Brief Description provides no bounds on the scope of the study or project. Expected cost, duration, participants,etc.</td></tr>
<tr><td colspan="4">Response: The SAR DT has made changes to the content of the SAR that are believed to have clarified the scope of the project.</td></tr>
<tr><td>PUD #2 of Grant County</td><td>☑</td><td></td><td>The scope seems appropriate, but I am afraid that it may create an overly burdensome standard during the drafting process.</td></tr>
<tr><td colspan="4">Response: The SAR DT appreciates your comments and concerns and will concentrate on only what is required for reliable system operations.</td></tr>
<tr><td>Salt River Project</td><td>☑</td><td></td><td>The scope appears reasonable in order to provide measurable reauirements. Please define the acronym "VRF" that appears as comments in the To Do List.</td></tr>
<tr><td colspan="4">Response: VRF = Violation Risk Factor. Each standard has a VRF assigned that represents the impact of non-compliance will have on grid reliability. The Violation Risk Factors would be used for the initial basis for determining enforcement action for violations.</td></tr>
<tr><td>WECC Reliability Coordination Comments Work Group</td><td>☑</td><td></td><td>Please define the acronym VRF that appears in the To Do List.
While we agree with the scope of the project, we feel that clarification of terms is necessary to facilitate an improved standard.

Inclusion of a requirement that all reliability coordinators have full backup control centers is included in first bullet of the To Do List. The meaning of "full" is unclear. The level of independence required in the second bullet of the To Do List needs to be specified. Does "independent" mean that separate RTU's and communication paths are needed for a backup facility, that there is no single point of failure shared between the two facilities, or does that term carry some other meaning?

The second bullet of the To Do List specifies that the backup facility must be capable of operating for a prolonged period of time, but the meaning of "prolonged" remains unclear.</td></tr>
<tr><td colspan="4">Response:
VRF = Violation Risk Factor. Each standard has a VRF assigned that represents the impact of non-compliance will have on grid reliability. The Violation Risk Factors would be used for the initial basis for determining enforcement action for violations.

The word “Full” only exists in Appendix B that is now listed as consideration only and not mandatory changes. It is possible (as pointed in several comments) that alternatives may exist to meet the requirements without requiring a “full” backup or complete duplication of a Primary Control Center.</td></tr>
</table>

Question #2			
Commenter	**Yes**	**No**	**Comment**
The terms Independent and Prolonged (as used in Appendix B) will be further defined by the SDT as appropriate with regard to backup control centers.			
Manitoba Hydro			Define "CESDT". This SAR says that a study of the backup capabilities that are needed to support reliable operations is required as part of this project. It is not clear what is the intended scope of this study. It might be helpful to the drafting team if the SAR indicated the expected time line to complete the work outlined in this SAR - perhaps by referring to the 2007-2009 work plan if timeframe is specified there.
Response: CESDT = Compliance Elements Standards Drafting Team. (This team added measures and compliance elements to the Version 0 standards that were incomplete when approved.) The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing. The timeline for the completion of this project is included in the Reliability Standards Development Work Plan 2007 – 2009 and therefore does not need to be included in the SAR. The estimated completion date shown in the work plan for the completion of balloting on the revised standard is 4Q08.			
Southern Company Services, Inc.	☑		
American Electric Power	☑		
Progress Energy Carolinas	☑		
Public Service Commission of SC	☑		
Entergy Services, Inc.	☑		

3. **Please identify any additional revisions that should be incorporated into this set of standards, beyond those that have already been identified in the SAR.**

Summary Consideration: Based on stakeholder comments, the drafting team made the following changes to the SAR:

- Clarified that the work of the Operating Committee's Backup Control Center Task Force study will be used as an input to the development of the standard's requirements. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing.
- Removed COM-001 from the list of standards addressed by the SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.
- Revised the default text in the 'Applicability' section of the SAR to include verbiage from Functional Model v3 as opposed to v2.
- Modified the applicability section of the SAR to include the Transmission Owner and clarified that the Transmission Owner should be considered as an applicable functional entity if it is operating a control center that is critical to Bulk Power System reliability but not registered as a Transmission Operator.
- Added language to clarify that the intent of the standard is to emphasize the continuation of needed functionality regardless of the manner in which it is achieved.

Question #3			
Commenter	**Yes**	**No**	**Comment**
NSTAR Electric ISO New England	☑		A study is referred to in the SAR. If some study is needed, what will be studied? What is in place today? What should be in place? If the study remains as part of the SAR, will the commenters decide what is required or will the requestor?
Response: The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing.			
IRC Standards Review Committee			If a Study is needed, what will be studied? What is in place today? What should be in place? If the study remains as part of the SAR, will the commenters decide what is required or will the requestor make that decision? The SAR requestor should be more senstive to the fact that these new standards will be formal mandatory requirements backed by the federal government. The idea that current requirments are unclear and ambiguous is no reason to write a proposal that is just as unclear and ambiguous. Note that this 'question' asks for input and yet includes a YES and NO box. Please take more care in the proposal.
Response: The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
The SAR DT has made changes to the content of the SAR that are believed to have clarified the scope of the project.			
Hydro One Networks Inc.		☑	A study is referred to in the SAR. If a study is needed, what will be studied? What is in place today? What should be in place? If the study remains as part of the SAR, will the commenters decide what is required or will the requestor? Hydro One has concerns regarding COM-001. R1.2 which states "Entities shall provide adequate and reliable telecommunications facilities to ensure the exchange of interconnection and operating information." We are concerned that this might be somewhat ambiguous and recommends improved definition of terms like "adequate", and perhaps some language that defines the parameters for the telecommunications facilities being provided. R3 says "Each RC, TOP and BA shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas." In consideration of the addition of compliance measures, we suggest that R3 be reviewed to confirm the objectives sought by this requirement. Further, that the language for R3 then be modified to more clearly convey the essence of the requirement. R4 says "Unless agreed to otherwise, each RC, Top and BA shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected BES. TOP and BA may use an alternate language for internal operations." We have concerns regarding how R4 would be monitored for compliance.
Response: The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing. After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR. The SAR DT has made changes to the content of the SAR that are believed to have clarified the scope of the project.			
NPCC CP9 Reliability Standards Working Group			A study is referred to in the SAR. If some study is needed, what will be studied? What is in place today? What should be in place? If the study remains as part of the SAR, will the commenters decide what is required or will the requestor? NPCC participating members have also expressed concern regarding COM-001. R1.2 which states "Entities shall provide adequate and reliable telecommunications facilities to ensure the exchange of interconnection and operating information." We are concerned that this might be somewhat ambiguous and recommends improved definition of terms like "adequate", and

Question #3			
Commenter	**Yes**	**No**	**Comment**
			perhaps some language that defines the parameters for the telecommunications facilities being provided. R3 says "Each RC, TOP and BA shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas." In consideration of the addition of compliance measures, we suggest that R3 be reviewed to confirm the objectives sought by this requirement. Further, that the language for R3 then be modified to more clearly convey the essence of the requirement. R4 says "Unless agreed to otherwise, each RC, Top and BA shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected BES. TOP and BA may use an alternate language for internal operations." We have concerns regarding how R4 would be monitored for compliance.
Response: The SAR DT is going to work closely with the OC Backup Control Center Task Force. Several members of that task force are also serving on the SAR DT. The goal of this effort is to start the standards effort at the time that the draft of the OC study is available. The project schedule supports this timing. After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR. The SAR DT has made changes to the content of the SAR that are believed to have clarified the scope of the project.			
Midwest ISO, Inc.	☑		Requirements for emergency communication should include the concept that the communication infrastructure be consistent between Reliability Coordinators, Transmission Operators, Balancing Authorities, and other applicable entities under the Functional Model.
Response: Any considerations for compatibility of communications facilities should be considered by the SDT We believe that the SAR as revised has sufficient flexibility to cover this issue.			
Southern Company Services, Inc.			It is recommended that a transition period of a couple of years be incorporated into the standard for being compliant with the new requirements. This will give the different entities time to get something constructed and maybe a new EMS system implemented before being compliant. In many cases there will be capital dollars that will need to be budgeted and spent and other major changes in order to be compliant.
Response: This is an important point and will be considered during the standard drafting phase by the SDT in their consideration of the implementation period.			
American Transmission Company	☑		ATC encourages the SC to select a wide range of individuals to work on these two standards. COM-001 will require the SDT to have some individuals with knowledge in telecommunication systems while EOP-008 requires individuals with an operations and facilities background.

Question #3			
Commenter	**Yes**	**No**	**Comment**
			The following comment is on the SAR's form. Section: Reliability Functions Function: Market Operator Existing language: Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch. ATC is concerned with the word "economic" being included in the description of Market Operator. The purpose of the SAR process is to develop reliability standards and the word economic being included in this description may cause problems/confusion down the road. Suggested language: Integrates energy, capacity, balancing, and transmission resources to achieve a reliability-constrained dispatch.
Response: The individuals selected by the SC for the SAR DT are experienced with operations, facilities, and communications. The membership of the SDT will be reviewed by the SC when the work is ready to progress to the standards writing phase. The SAR has been revised to include verbiage from Functional Model v3 as opposed to v2 text that appears in the original SAR and that should help to clear up any confusion with applicable entity assignment. The Market Operator is not an applicable entity for this standard.			
PUD #2 of Grant County	☑		It should be communicated clearly that any transition to a back up center should allow for the contunued normal operation of tasks and functions. The standard should be built on this concept, and should still allow for the type of tasks being done by the entitiy, and the level of effect that the entity has on the BES.
Response: This is an important point and will be considered by the SDT during the standard drafting phase.			
Progress Energy Carolinas	☑		We agree that the EOP-008 standard should require that Backup Control Centers to be functionally viable for managing long-term operation of the bulk electric system from the backup control center facility. With respect to COM-001, which this SAR puts in tandem with EOP-008, the requirement to maintain dedicated and redundant communications channels and plans for continued operations with loss of telecommunications should be required of LSEs and Generator Operators as well. This revision will require third party generators to provide for adequate communications to facilitate reliable operations for the BAs and TOPs.
Response: After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.			
Manitoba Hydro			COM-001-0 and -1 R1 what is "adequate", needs to be defined. "Interconnection and operating information",

<table>
<tr><th colspan="4">Question #3</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>does this include data transfer as well as communications?
R1.2 Should this not read: "Between the Reliability Coordinators, Transmission Operators, and Balancing Authorities." This sounds like one way communications between the RC and TO's and BA's.
R2 - define "vital".
R4 - "Unless agreed to otherwise" needs to be defined by whom?
COM-001-1
R1 - Missing the word "for" between "facilities the".

EOP-008-0
R1.5 - Need to define "periodic tests", this could vary from one company testing annually to another company testing every 5 years, to each periodic testing is met.
This SAR should require that Violation Risk Factors be assigned to the requirements of COM-001 and EOP-008 and be included in the subsequently . Coordinate assignment of VRF's with current ballot on Version 0 VRF and proposed VRF's for Version 1, as appropriate.</td></tr>
<tr><td colspan="4">Response:
After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR.

Clarification of the EOP-008 standard along the lines suggested by this comment is within the scope of the SAR and would be undertaken by the standard drafting team.

Existing and approved violation risk factors will be taken into account as appropriate by the SDT.</td></tr>
<tr><td>Independent Electricity System Operator</td><td></td><td>☑</td><td>(1) Without knowing the bounds of the work and the purpose and expected outcomes of the "study", we are unable to offer further comments but feel uncomfortable to be asked to support this SAR to start standard development work.

(2) Since some transmission owning entities may not register as a TOP but may have local control tasks assigned to it by the TOP, the Transmission Owner should also be included as an Applicable entity for both EOP-008 and COM-001.</td></tr>
<tr><td colspan="4">Response:
The study team referred to in the SAR is the Backup Control Center Task Force. The task force was authorized by the NERC Operating Committee to develop the concepts of backup control and to provide the technical basis for developing the backup standards. The task force report will be available to the Standards Drafting Team. The information from the report will be used by the standard drafting team as one of the inputs when drafting the standard. Five members of the task force are also members of the SAR drafting team. This provides close liaison between the study group and the drafting team.

The SAR Drafting Team agrees that in some cases (as described in the Brief Description section of the revised SAR) the Transmission Owner should be considered as an applicable functional entity to deal with the situation where Transmission Owners are operating control centers</td></tr>
</table>

Question #3			
Commenter	**Yes**	**No**	**Comment**
that are critical to Bulk Power System reliability but are not registered as Transmission Operators. The SAR has been revised accordingly and a question on this subject has been posted for the re-issuance of the SAR.			
Salt River Project	☑		Regarding R1.5, where it talks of ". . . conducting periodic tests, at least annually . . ." I would suggest monthly instead, but this has effects outside of just CA. Also, the NERC proposed changes talk of " . . . (2) be capable of operating for a prolonged period of time; . . ." And we have a 10 year schedule to add all of our existing RTUs to TCC. I assume that if TCC became our only dispatch center, would we accelerate this?
Response: Clarification of the EOP-008 standard along the lines suggested by this comment is within the scope of the SAR and would be undertaken by the standard drafting team. Issues such as raised here in part 2 of your comment are not within the scope of this SAR DT.			
Bonneville Power Administration	☑		Reliability Coordinators (RC's) are dependent on data from control areas and transmission owners. RCs also rely on control areas and transmission owners to control the transmission system via SCADA, generators using AGC or voice communications to others like generator operators. Therefore Control Areas and Transmission Owners must also have backup facilities to provide critical data and controls even after the loss of their own control center. Voice circuits to backup centers are also needed. Another problem area is Uninterruptible Power System or UPS. Failures of UPS are a leading factor in control center failure. Also, during a widespread blackout, UPS failures have occurred causing control center failure. Communications circuits are needed from backup facilities for control areas or transmission owners to critical Reliability centers and backup centers, critical adjacent utilities, and large generators. COM-001 does not address the need for voice or data communications circuits to generators. These circuits are required for AGC operation and also during emergencies including black start restoration. It may be addressed elsewhere in NERC standards.
Response: The SAR Drafting Team agrees that in some cases (as described in the Brief Description section of the revised SAR) the Transmission Owner should be considered as an applicable functional entity to deal with the situation where Transmission Owners are operating control centers that are critical to Bulk Power System reliability but are not registered as Transmission Operators. The SAR has been revised accordingly and a question on this subject has been posted for the re-issuance of the SAR. Critical equipment such as UPS will be considered at the standards drafting stage of this project. After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in			

Question #3			
Commenter	**Yes**	**No**	**Comment**
the scope of this SAR.			
Xcel Energy – NSP	☑		Review training requirements to insure consistency and adequacy.
Response: Training is an important item and it will be considered.			
Entergy Services, Inc.			COM-001-0/1 R1 needs clarification for "adequate and reliable". R2 needs "and/or" clarification - is active monitoring satisfactory for compliance in lieu of testing? What does it mean to "alarm" a vital telecommunication facility? Is it the same as testing? Should a periodicity for testing be explicit? How is "vital" defined? How is "special attention" defined? R3 - what does "coordinate telecommunications" mean? Also, this requirement has no measure - should there be one? EOP-008-0 Purpose - I have heard a lot of debate amongst industry members about whether a physical back up facility must exist or not, or if one just needs to have a 'plan'. This standard should make it explicitly clear as to whether a physical facility must exist. I believe it would be difficult to ensure the viability of a plan as required in R1.5 unless a physical facility existed. R1.8 - what constitutes "interim" provisions? The standard should consider stating the required time to make a back up center operational. PER-003-0 has a seemingly out of place requirement in its measures section (M1.2) about having NERC certified operators at all times except for 4 hours for transition to a back up center. This might be a starting point. VRFs - many appear to be administrative in nature, yet are rated as Medium. Please include in the review.
Response: After discussion the SAR DT has decided to delete COM-001 from this SAR. COM-001 deals with communications in a generic sense and does not specifically relate to backup facilities. Consideration for communications support explicitly for backup facilities will be included in the scope of this SAR. The intent of the project is to emphasize the continuation of needed functionality regardless of the manner in which it is achieved. Clarification of the EOP-008 standard along the lines suggested by this comment is within the scope of the SAR and would be undertaken by the standard drafting team. Review of VRF is required of all standard drafting teams.			
Tennessee Valley Authority		☑	
WECC Reliability Coordination Comments Work Group		☑	

Question #3			
Commenter	**Yes**	**No**	**Comment**
ITC Transmission			No comment.
Entergy Services, Inc.			We have no additional revisions at this time.
American Electric Power			None identified at this time.
Kansas City Power & Light Company			This does not require a yes/no response. No other comments.
Public Service Commission of SC			None identified.
MISO, IPL, JDRJC Associates			This does not appear to be a yes-no question.

Standard Authorization Request Form

Title of Proposed Standard	Back-up Facilities Project 2006-04
Request Date	October 26, 2006

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Sam Brattini	☐	New Standard
Primary Contact	Sam Brattini	X	Revision to existing Standard
Telephone Fax	215-997-4500 x270 215-997-3818	☐	Withdrawal of existing Standard
E-mail	sam.brattini@us.kema.com	☐	Urgent Action

Purpose

Applicable Standards: EOP-008: Plans for Loss of Control Center Functionality

The purpose of revising these standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems — the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Consider other general improvements as described in Appendix A.
4. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in the attached review sheets.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need

As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards, Phase III & IV standards, and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and Phase III & IV translations. The standard in this project is a Version 0 standard.

Brief Description

Revise EOP-008-0 Plans for Loss of Control Center Functionality to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

Detailed Description
The requirements in EOP-008 need additional specificity. The development revision to EOP-008 may include other improvements to the standard deemed appropriate by the standard drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. In addition, the efforts of the OC Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008. Also, there may be backup facility requirements in some other standards, and those requirements should be considered for movement into this standard. The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational. The objective of EOP-008 should be to emphasize the continuation of functionality needed for reliable system operation regardless of the manner in which it is achieved. Additionally, consideration for communications required to explicitly support backup facilities will be included in the scope of this revision as applicable.
The reliability requirements for EOP-008 are such that simply checking the box in the Reliability Functions table for applicable functional model entities may not be appropriate. In some cases it may impose obligations on entities that are not truly warranted from a Bulk Power System reliability perspective (such as a small Transmission Operator that is only operating a radial transmission system), and at the other end it may not capture entities that are using control centers to perform critical Bulk Power System reliability tasks under delegation agreements. The basic intent is to apply this standard to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System. In concept this would include: • All Reliability Coordinators, • All Balancing Authorities, • All Transmission Operators, except those for which it is determined that loss of primary control capability would not impose a significant real-time reliability risk on the Bulk Power System • Any entity performing reliability functions as a result of delegation of tasks from any Reliability Coordinator, Balancing Authority or Transmission Operator. An example of this situation would be a transmission control center operated by an entity that is registered as a Transmission Owner but not registered as a Transmission Operator. In order to afford the standard drafting team sufficient scope coverage to consider this delegation question, Transmission Owner is also checked as being a reliability function to which the standard will apply.
Note that Appendix B is an informative attachment that contains material for consideration in the standards revision process. It should not be considered to contain mandatory changes to the standard.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
X	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
IRO-002	Currently contains provisions for backup facilities.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A

Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard 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 practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

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

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **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.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Reliability Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: EOP-008 Technical Issues List

Excerpted from NERC Reliability Standards Development Plan: 2007 - 2009

Standard Review Form Project 2006-04 Back-up Facilities		
Standard #	**EOP-008-0**	**Comments**
Title	Plans for Loss of Control Center Functionality	Okay but could probably drop 'Plans for'.
Purpose		Okay
Applicability		Isn't the reliability entity the TSP and not the TO as per the FM?
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	Grammar error in R1.2
	Result or Outcome	Missing
Measures		Measure doesn't define required evidence.
Issues to Consider	FERC NOPR o Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability. o Provision for backup capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center. FERC staff report o Distinction between providing plans and proving capabilities o Independence from primary control center Regional Fill-in-the-Blank Team Comments o No comments V0 Industry Comments o How does staff know control center is lost? o How is backup control achieved? o Max. time to restore capabilities VRF comments o R1 - Not having a written plan does not directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading o R1.1 - Not having a written plan is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.	

Standard Authorization Request Form

Title of Proposed Standard	Back-up Facilities Project 2006-04
Request Date	October 26, 2006

SAR Requestor Information	SAR Type (*Check a box for each one that applies.*)	
~~Name Reliability Standards Development Plan: 2007 – 2009~~ Name Sam Brattini	☐	New Standard
Primary Contact ~~Richard Schneider (To be replaced by SAR DT Chair when the SAR DT is appointed)~~Sam Brattini	X	Revision to existing Standard
Telephone ~~609-452-8060~~215-997-4500 x270 Fax 215-997-3818	☐	Withdrawal of existing Standard
~~E-mail Richard.schneider@nerc.net~~E-mail sam.brattini@us.kema.com	☐	Urgent Action

Purpose

Applicable Standards: ~~COM-001: Telecommunications~~ EOP-008: Plans for Loss of Control Center Functionality

The purpose of revising these standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems — the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. ~~Incorporate~~Consider other general improvements as described in ~~the standards development work plan (see attachments)~~Appendix A.
4. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in the attached review sheets.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need

As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards, Phase III & IV standards, and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and Phase III & IV translations. The ~~two standards~~standard in this ~~set are both~~project is a Version 0 standard~~s~~.

Brief Description

Revise EOP-008-0 Plans for Loss of Control Center Functionality to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

~~Brief~~Detailed Description

~~A study of the backup capabilities that are needed to support reliable operations is required as part of this project.~~

The requirements in EOP-008 need additional specificity. The ~~study conducted before this~~ development revision to EOP-008 may include other improvements to the standard ~~is finalized should look at the facility requirements identified in the certification standards and identify which of these are essential to reliable operations.~~

~~There are backup facility requirements in some other standards, and those requirements should be moved into this standard.~~

~~The development may include other improvements to the standards~~ deemed appropriate by the standard drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. In addition, the efforts of the OC Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008. Also, there may be backup facility requirements in some other standards, and those requirements should be considered for movement into this standard.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational. The objective of EOP-008 should be to emphasize the continuation of functionality needed for reliable system operation regardless of the manner in which it is achieved.

Additionally, consideration for communications required to explicitly support backup facilities will be included in the scope of this revision as applicable.

The reliability requirements for EOP-008 are such that simply checking the box in the Reliability Functions table for applicable functional model entities may not be appropriate. In some cases it may impose obligations on entities that are not truly warranted from a Bulk Power System reliability perspective (such as a small Transmission Operator that is only operating a radial transmission system), and at the other end it may not capture entities that are using control centers to perform critical Bulk Power System reliability tasks under delegation agreements.

The basic intent is to apply this standard to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System. In concept this would include:

- All Reliability Coordinators,
- All Balancing Authorities,
- All Transmission Operators, except those for which it is determined that loss of primary control capability would not impose a significant real-time reliability risk on the Bulk Power System
- Any entity performing reliability functions as a result of delegation of tasks from any Reliability Coordinator, Balancing Authority or Transmission Operator. An example of this situation would be a transmission control center operated by an entity that is registered as a Transmission Owner but not registered as a Transmission Operator. In order to afford the standard drafting team sufficient scope coverage to consider this delegation question, Transmission Owner is also checked as being a reliability function to which the standard will apply.

Note that Appendix B is an informative attachment that contains material for consideration in the standards revision process. It should not be considered to contain mandatory changes to the standard.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	Reliability ~~Authority~~Coordinator	~~Ensures~~Responsible for the real-time operating reliability of ~~the bulk transmission system within~~ its Reliability ~~Authority area. This is the highest~~Coordinator Area in coordination with its neighboring Reliability ~~Authority.~~Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within ~~its metered boundary~~a Balancing Authority Area and supports ~~system~~Interconnection frequency in real time.
☐	Interchange ~~Authority~~Coordinator	~~Authorizes~~Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced ~~Interchange Schedules.~~interchange schedules between Balancing Authority Areas.
☐	Planning ~~Authority~~Coordinator	~~Plans the Bulk Electric System.~~Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a ~~long-term (~~>one year~~)~~ plan for the resource adequacy of its specific loads within a Planning ~~Authority~~Coordinator area.
☐	Transmission Planner	Develops a ~~long-term (~~>one year~~)~~ plan for the reliability of ~~transmission systems~~the interconnected Bulk Electric System within its portion of the Planning ~~Authority~~Coordinator area.
☐	Transmission Service Provider	~~Provides~~Administers the transmission tariff and provides transmission services ~~to qualified market participants~~ under applicable transmission service agreements (e.g., the pro forma tariff).
~~☐~~X	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	~~Operates and maintains the transmission facilities, and executes switching orders.~~Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
~~X~~☐	Distribution Provider	~~Provides and operates the "wires" between the transmission system and the customer.~~Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation ~~unit(s).~~facilities.
~~X~~☐	Generator Operator	Operates generation unit(s) to provide real and ~~performs the functions of supplying energy and Interconnected Operations Services.~~reactive power.
☐	Purchasing-Selling Entity	~~The function of purchasing~~Purchases or ~~selling~~sells energy, capacity, and ~~all~~ necessary ~~Interconnected Operations Services~~reliability-related services as required.

☐	Market Operator	~~Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.~~Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and related ~~generation~~reliability-related services) to serve the ~~end user.~~End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
IRO-002	Currently contains provisions for backup facilities.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

~~Standard Review Form Project 2006-04 Back-up Facilities~~		
~~**Standard #**~~	~~**COM-001-0**~~	~~**Comments**~~
~~**Title**~~	~~Telecommunications~~	~~Okay~~
~~**Purpose**~~		~~Not sure that we need to include entities in Purpose.~~
~~**Applicability**~~		~~Not sure about inclusion of NERCNet~~
~~**Requirements**~~	~~*Conditions*~~	~~Interconnection is capitalized.~~
	~~*Who?*~~	~~Okay~~
	~~*Shall do what?*~~	~~R1.4 – should spell out applicability and extent for redundancy~~ ~~R2 – provide periodicity of testing~~ ~~R4 – cite communication protocol such as two-part communications~~ ~~R6 – probably doesn't belong here~~ ~~CESDT:~~ ~~R1 duplicated by COM-002 R1~~ ~~R2 – 'special attention'~~ ~~R3 – 'provide a means' & 'ability to investigate'~~
	~~*Result or Outcome*~~	~~Missing~~
~~**Measures**~~		~~CESDT addressing but:~~ • ~~4M for 6R~~ • ~~Still lacks measurability~~
~~**To Do List**~~	~~FERC NOPR~~ o ~~Include Measures and Levels of Non-Compliance;~~ o ~~Include generator operators and distribution provider as applicable entities; and~~ o ~~Include requirements for communication facilities for use during emergency situations.~~ ~~FERC staff report~~ o ~~Lacks adequacy, redundancy and routing requirements~~ o ~~Generation owners missing~~ o ~~Expect new standard in November~~ ~~V0 Industry Comments~~ o ~~Redundant with Policy 5A, R1~~ o ~~Many players missing~~ o ~~Apply R1 to all but smallest entities~~ ~~VRF comments~~ o ~~R6 – administrative requirement~~	
~~**Misc. Items**~~		~~Compliance not specified but appears in CESDT version~~

Appendix A

Reliability Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard 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 practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

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

Clear Language

Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality

Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements

In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology

To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **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.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Reliability Entity'

Fill-in-the-blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: EOP-008 Technical Issues List

Excerpted from NERC Reliability Standards Development Plan: 2007 - 2009

Standard Review Form Project 2006-04 Back-up Facilities		
Standard #	**EOP-008-0**	**Comments**
Title	Plans for Loss of Control Center Functionality	Okay but could probably drop 'Plans for'.
Purpose		Okay
Applicability		Isn't the reliability entity the TSP and not the TO as per the FM?
Requirements	*Conditions*	Okay
	Who?	Okay
	Shall do what?	Grammar error in R1.2
	Result or Outcome	Missing
Measures		Measure doesn't define required evidence.
~~To Do List~~Issues to Consider	FERC NOPR o Include a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability. o Provision for backup capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center. FERC staff report o Distinction between providing plans and proving capabilities o Independence from primary control center Regional Fill-in-the-Blank Team Comments o No comments V0 Industry Comments o How does staff know control center is lost? o How is backup control achieved? o Max. time to restore capabilities VRF comments o R1 - Not having a written plan does not directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading o R1.1 - Not having a written plan is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.	

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☐ No

   Comments:

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☐ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

February 15, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Three 30-day Comment Periods Open

The Standards Committee (SC) announces the following standards actions:

SAR to Amend the Assess Transmission Future Needs and Develop Transmission Plans SAR Posted for 30-day Comment Period February 15–March 16, 2007

The SAR to amend the already-approved SAR for Assess Transmission Future Needs and Develop Transmission Plans (Project 2006-02) proposes to add TPL-005-0 and TPL-006-0 to the list of transmission planning standards currently addressed (TPL-001 through TPL-004), to consider issues raised by FERC and stakeholders regarding this set of standards, and to bring the entire set of standards into conformance with the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure. Please use the comment form to provide comments on this SAR amendment.

First Standard (MOD-001-1) in the Series of ATC/TTC/AFC Revisions Posted for 30-day Comment Period February 15–March 16, 2007

The first standard modified under Project 2006-07, MOD-001-1 — ATC and AFC Calculation Methodologies, requires the Transmission Service Provider to document and use a single methodology for calculating ATC or AFC. The drafting team is soliciting comments on the proposed requirements before developing the measures and compliance elements. Please use the comment form to provide comments on this draft standard's proposed requirements.

Second Draft of SAR for Backup Facilities Posted for 30-day Comment Period February 15–March 16, 2007

The SAR for Project 2006-04 proposes modifying EOP-008-0 — Plans for Loss of Control Center Functionality. The revisions to EOP-008 focus on ensuring the continuation of functionality needed for reliable system operation regardless of the manner in which it is achieved. The modifications will consider issues raised by FERC and stakeholders about this standard, and will bring the standard into conformance with the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure. Please use the comment form to provide comments on this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	James H. Sorrels, Jr.	
Organization:	AEP	
Telephone:	614-716-2370	
E-mail:	jhsorrels@aep.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008
- Removed COM-001 from the list of standards included in the scope of this project
- Modified the SAR to clarify that there “may” be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement
- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard
- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words “Backup Facilities” in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☒ Yes

   ☐ No

   Comments:

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: There should be a provision for the ability to demonstrate backup functionality if arranged/contracted with another reliability entity, as long as that entity can demonstrate their backup capability to meet the requirements and measures.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	Jason Shaver	
Organization:	American Transmission Co.	
Telephone:	262 784 8124	
E-mail:	jshaver@atcllc.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☒ Yes

   ☐ No

   Comments:

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: ATC does not support the proposed exclusion for Transmission Operators. The exclusion allows an exempt Transmission Operator to determine post event how they should continue to monitor their transmission system. The result would be an unmonitored transmission system for possibly days or months.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	Melinda Montgomery	
Organization:	Entergy Services, Inc.	
Telephone:	870 541 4578	
E-mail:	mmontg3@entergy.com	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there “may” be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words “Backup Facilities” in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: It is clear that the standard would apply to the Tranmission Operator. It is considerably less clear when it would apply to a transmission owner that is not also a transmission operator. I am not aware of a case where the Transmission Owner is operating a control center and performing functions that have impact on the reliability of the Bulk Power System, but such a situation could exist. In that situation, the transmission owner might be considered to be delegated such tasks by the transmission operator or some other functional entity. My concern is that there may be some shades of grey, where it is not clear whether or not a transmission owner is required to comply with the standard.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments:

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	Steve Myers	
Organization:	ERCOT	
Telephone:	512-248-3077	
E-mail:	smyers@ercot.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☒ Yes

   ☒ No

   Comments: If the Transmission Owner is performing tasks in accordance with a delegation agreement between the Transmission Owner and the Transmission Operator, the Transmission Operator is still responsible for meeting the requirements of the function. The delegation agreement should cover and include the relevant requirements for backup functionality of the Transmission Owner. I believe the NERC standard should show applicability to the Transmission Operator.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: The SAR should clearly show that the backup requirements apply to the functionality rather than specifying how to do it. In other words, say they must be able to do "what" and not that they must have a backup facility (which is a "how"). This is not to say that I do not believe that backup facilities are important. They are important, and I believe it is prudent for the responsible entities to have them. However, the reliability requirement is that the responsible entity be able to perform under need.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Greg Lange	
Organization:	Grant County PUD (GCPD)	
Telephone:	509 754-5061	
E-mail:	glange@gcpud.org	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: If a transmission owner operates a control center, they are a transmission operator. Therefore, the SAR doesn't need to address transmission owners. They just need to properly register their entity.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments: EOP-008 only discusses loss of primary control facilities. No need to look at standards dealing with normal operations.

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: Please change the name of the SAR from Backup Facilities to Loss of Primary Control Facilities. Revision of EOP-008 should not specify requirement for a backup control center. There are several other viable ways to maintain or resume control with a loss of primary facilities. Even if the drafters intent is correct, the title is confusing. If it is the intent of the drafters/sponsor to create a requirement for the existance of backup control centers, then a new SAR should be written that is not listed as a revision of an existing standard.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Roger Champagne	
Organization:	Hydro-Québec TransÉnergie (HQT)	
Telephone:	514 289-2211, X 2766	
E-mail:	champagne.roger.2@hydro.qc.ca	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: Although HQT see value, from a reliability perspective, to have "large" TOs with control centers, to have back-up facilities, it seems more appropriate to leave the details of what TO backup facilities are necessary in the individual TOP/TO operating agreements when a task is delegated. If a TO perform tasks that might impact the BPS, maybe they should register as a TOP.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments:

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Ron Falsetti		
Organization: IESO		
Telephone: 905-855-6187		
E-mail: ron.falsetti@ieso.ca		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008
- Removed COM-001 from the list of standards included in the scope of this project
- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement
- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard
- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: Even though we see value, from a reliability perspective, to have "large" TOs with control centers, to have back-up facilities, we are not comfortable with the idea of mandating this through a NERC standard. We strongly feel that the details of what TO backup facilities are necessary, should be dealt between the TOP and TO in their respective operating agreements.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments:

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Kathleen Goodman	
Organization:	ISO New England	
Telephone:	(413) 535-4111	
E-mail:	kgoodman@iso-ne.com	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: Per the NERC Functional Model, the Transmission Operator operates the control centers.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: There are other SARs that have been posted recently that includes reviews and potential changes to standards this SAR will impact. ISO New England believes that the Standards Committee should work to resolve multiple SARs covering the same standards to prevent confusion and potential loss of changes. It is important that these SARs are sequenced properly to ensure that there are not any lost changes.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Brian Thumm	
Organization:	ITC Transmission	
Telephone:	248.374.7846	
E-mail:	bthumm@itctransco.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: If a Transmission Owner operates a control center, then they are a Transmission Operator. They should register as such.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments:

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Michael Gammon	
Organization:	Kansas City Power & Light	
Telephone:	816-654-1242	
E-mail:	mike.gammon@kcpl.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☒ Yes

   ☐ No

   Comments:

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: No other comments.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Robert Coish	
Organization:	Manitoba Hydro	
Telephone:	204-487-5479	
E-mail:	rgcoish@hydro.mb.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☒ Yes

   ☒ No

   Comments: If the Transmission Owner operates a control centre then it should be registered as a Transmission Operator and meet the back up facility requirements.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments:

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs or ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 – Regional Reliability Organizations or Regional Entities</td></tr>
</table>

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

Group Name:	Midwest ISO Stakeholders' Standards Collaboration Participants
Lead Contact:	**Jason Marshall**
Contact Organization:	**Midwest ISO**
Contact Segment:	**2**
Contact Telephone:	**317-249-5494**
Contact E-mail:	**jmarshall@midwestiso.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Cyrulewski	**JDRJC Associates**	**RFC**	8

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: If Transmission Owner is operating a control center, this would make them a transmission operator and they should register as one.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments: Since this SAR is dealing directly with backup capabilities, removing consideration of COM-001 makes sense. However, this causes a fundamental question. Should the standards defining primary control center capabilities include the back up capabilities as well? If so, a supplemental SAR will be required and then COM-001 would need to be considered.

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: There are other SARs that have been posted recently that includes reviews and potential changes to standards this SAR will impact. For example, the Reliability Coordination (Project 2006-06) SAR will include modifications to IRO-002. This SAR should address how these changes will be coordinated with the Reliability Coordination SAR, other existing SARs and any other SAR that is expected to be proposed from the NERC Reliability Standards Work Plan.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs or 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 or Regional Entities

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

Group Name:	NSRS
Lead Contact:	**Carol Gerou**
Contact Organization:	**MRO**
Contact Segment:	**10**
Contact Telephone:	**218-722-1972 ext. 2058**
Contact E-mail:	**cgerou@mnpower.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	**WPSR**	**MRO**	10
Terry Bilke	**MISO**	**MRO**	10
Al Boesch	**NPPD**	**MRO**	10
Larry Brusseau	**MRO**	**MRO**	10
Robert Coish, Chair	**MHEB**	**MRO**	10
Carol Gerou	**MP**	**MRO**	10
Ken Goldsmith	**ALT**	**MRO**	10
Todd Gosnell	**OPPD**	**MRO**	10
Jim Haigh	**WAPA**	**MRO**	10
Pam Oreschnik	**XCEL**	**MRO**	10
Dick Pursley	**GRE**	**MRO**	10
Dave Rudolph	**BEPC**	**MRO**	10
Rick Liljegren	**MP**	**MRO**	10
Michael Brytowsk, Secretary	**MRO**	**MRO**	10
27 Additional MRO Members	**Not Named Above**	**MRO**	10

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☒ Yes

   ☐ No

   Comments: These facilities are critical to the reliable operation of the Bulk Power system therefore flexibility to include a transmission owner as an applicable entity is reasonable.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: 1. Remove migitation time horizons form the SAR because they are not defined and they are not part of the Standards Development Procedure.
   2. Need to specific which standards are included in this SAR to be modified other than standard IRO-002.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 – Regional Reliability Organizations or Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:	NPCC CP9, Reliability Standards Working Group		
Lead Contact:	**Guy V. Zito**		
Contact Organization:	**Northeast Power Coordinating Council**		
Contact Segment:	**10**		
Contact Telephone:	**212-840-1070**		
Contact E-mail:	**gzito@npcc.org**		

Additional Member Name	Additional Member Organization	Region*	Segment*
Ralph Rufrano	New York Power Authority	NPCC	1
Herb Schrayshuen	National Grid US	NPCC	1
Murale Gopinathan	Northeast Utilities	NPCC	1
Jerad Barnhart	NStar	NPCC	1
Roger Champagne	TransEnergie HydroQuebec	NPCC	1
Kathleen Goodman	ISO-New England	NPCC	2
Bill Sehemley	ISO-New England	NPCC	2
Ron Falsetti	The IESO	NPCC	2
Randy McDonald	New Brunswick System Operator	NPCC	2
Al Adamson	New York St. Reliability Council	NPCC	10
Greg Campoli	New York ISO	NPCC	2
Guy Zito	NPCC	NPCC	10
Don Nelson	MA Dept. of Tele. and Energy	NPCC	9

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: Although NPCC participating members see value, from a reliability perspective, to have "large" TOs with control centers, to have back-up facilities, there is trepidation with the idea of mandating this through a NERC standard. It is more appropriate to leave the details of what TO backup facilities are necessary in the individual TOP/TO operating agreements.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments:

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Michael Calimano	
Organization:	New York Independent System Operator	
Telephone:	518-356-6129	
E-mail:	gcampoli@nyiso.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008
- Removed COM-001 from the list of standards included in the scope of this project
- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement
- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard
- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: Per the NERC Functional Model, the Transmission Operator operates the control centers and should have sole responsibility for BPS Operation. The TOP has responsibility to ensure others who are supporting their control center, such as a TO, can do so as defined in agreements or reliability plans. A transmission owner with a conrol center that takes independent action on the BPS should be register as a TOP.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: There are other SARs that have been posted recently that includes reviews and potential changes to standards this SAR will impact. The IRC believes that the Standards Committee should work to resolve multiple SARs covering the same standards to prevent confusion and potential loss of changes. It is important that these SARs are sequenced properly to ensure that there are not any lost changes.

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words “Backup Facilities” in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Wayne Lewis	
Organization:	Progress Energy	
Telephone:	919-546-7936	
E-mail:	wayne.lewis@pgnmail.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or 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, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☒ Yes

   ☐ No

   Comments:

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments:

Please use this form to submit comments on the second draft of the SAR for Backup Facilities. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs or ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations or Regional Entities

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

Group Name: Standards Review Comittee

Lead Contact: **Charles Yeung**

Contact Organization: **SPP**

Contact Segment: **2**

Contact Telephone: **832-724-6142**

Contact E-mail: **cyeung@spp.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Alicia Daugherty	PJM	RFC	2
Mike Calimano	NYISO	NPCC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Anita Lee	AESO	WECC	2
Steve Myers	ERCOT	ERCOT	2
Bill Phillips	MISO	RFC+	2
		+MRO	
		+SERC	

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The revised SAR clarifies that this project revises EOP-008-0, Plans for Loss of Control Center Functionality, to emphasize the continuation of functionality needed by Reliability Coordinators, Balancing Authorities, and Transmission Operators for reliable system operation regardless of the manner in which it is achieved.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational, including consideration for communications required to explicitly support backup facilities.

The drafting team made several changes to the SAR based on stakeholder comments, including the following:

- Clarified that the work of the Operating Committee Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008

- Removed COM-001 from the list of standards included in the scope of this project

- Modified the SAR to clarify that there "may" be some requirements for backup capabilities in other reliability standards and added IRO-002 to the list of related standards because it does contain a backup facility requirement

- Clarified that Appendix B is an informative attachment that contains material for consideration in the standards revision process, but should not be considered to contain mandatory changes to the standard

- Clarified that the standard will apply to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System — and includes the Reliability Coordinator, Balancing Authority, Transmission Operator, and any entity (including the Transmission Owner) performing reliability functions as a result of delegation of tasks from those entities

Please review the revised SAR and then answer the questions in this comment form. Comments must be submitted by **March 16, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Backup Facilities" in the subject line.

You do not have to answer all questions.

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

1. The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard?

   ☐ Yes

   ☒ No

   Comments: Per the NERC Functional Model, the Transmission Operator operates the control centers.

2. The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?

   ☒ Yes

   ☐ No

   Comments:

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

   Comments: There are other SARs that have been posted recently that includes reviews and potential changes to standards this SAR will impact. The IRC believes that the Standards Committee should work to resolve multiple SARs covering the same standards to prevent confusion and potential loss of changes. It is important that these SARs are sequenced properly to ensure that there are not any lost changes.

The Backup Facilities SAR requesters thank all commenters who submitted comments on Draft 2 of the Backup Facilities SAR. This SAR was posted for a 30-day public comment period from February 8 through March 9, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 7 sets of comments, including comments from 48 different people from 44 companies and organizations representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending that the SC approve the SAR and move this project on to the standards drafting stage.

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/Backup_Facilities.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]

No changes were made to the SAR as a result of the comments received. While there were some comments received concerning the inclusion of specific applicable entities in the SAR, the SAR DT has responded to those comments. However, there is a minority opinion within the SAR DT concerning the applicability of the SAR and eventual standard to the TO. The SAR DT wanted to maintain for the future SDT the possibility of including the TO as an applicable entity to address the problem that may arise when a TOP delegates critical tasks to the TO. The SAR DT sees this as a larger problem that needs to be addressed in the respective Delegation Agreements, NERC Functional Model and/or the NERC entity registration process.

The drafting team did modify the SAR to replace the items listed under the FERC NOPR with the items now listed in FERC Order 693 and to remove references to 'Phase III & IV' standards.

[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.	Wayne Lewis	Progress Energy	✓		✓		✓	✓				
2.	Melinda Montgomery	Entergy Services, Inc.	✓									
3.	Greg Lange	Grant County PUD			✓							
4.	Roger Champagne	Hydro-Québec TransÉnergie	✓									
5.	Kathleen Goodman	ISO New England		✓								
6.	Brian Thumm	ITC Transmission	✓									
7.	Ralph Rufrano (G1)	NYPA	✓									
8.	Herb Schrayshuen (G1)	NGrid	✓									
9.	Murale Gopinathan (G1)	NU	✓									
10.	Jerad Barnhart (G1)	NStar	✓									
11.	Roger Champagne (G1)	TransÉnergie Hydro-Québec	✓									
12.	Kathleen Goodman (G1)	ISO New England		✓								
13.	Bill Shemley (G1)	ISO New England		✓								
14.	Ron Falsetti (I)	IESO		✓								
15.	Randy MdDonald (G1)	NBSO		✓								
16.	Al Adamson (G1)	NYSRC		✓								
17.	Greg Campoli (G1)	NYISO		✓								
18.	Guy Zito (G1)	NPCC										✓
19.	Don Nelson (G1)	MA Dept. of Tele. And Energy									✓	
20.	James H. Sorrels, Jr	AEP	✓				✓	✓				
21.	Jason Shaver	ATC	✓									
22.	Steven Myers	ERCOT		✓								
23.	Michael Gammon	KCP&L	✓									
24.	Robert Coish	Manitoba Hydro	✓				✓	✓				
25.	Jason Marshall (G2)	MISO		✓								
26.	Jim Cyrulewski (G2)	JDRJC Associations								✓		
27.	Carol Gerou (G3)	MRO										✓
28.	Neal Balu (G3)	WPSR										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
29.	Terry Bilke (G3)	MISO										✓
30.	Al Boesch (G3)	NPPD										✓
31.	Larry Brusseau (G3)	MRO										✓
32.	Robert Coish, Chair (G3)	MHEB										✓
33.	Ken Goldsmith (G3)	ALT										✓
34.	Todd Gosnell (G3)	OPPD										✓
35.	Jim Haigh (G3)	WAPA										✓
36.	Pam Oreschnik (G3)	XCEL										✓
37.	Dick Pursley (G3)	GRE										✓
38.	Dave Rudolph (G3)	BEPC										✓
39.	Rick Liljegren (G3)	MP										✓
40.	Michael Brytowski, Secretary (G3)	MRO										✓
41.	Charles Yeung (G4)	SRC		✓								
42.	Alicia Daugherty (G4)	PJM		✓								
43.	Mike Calimano (G4)	NYISO		✓								
44.	Ron Falsetti (G4)	IESO		✓								
45.	Matt Goldberg (G4)	ISO-NE		✓								
46.	Brent Kingsford (G4)	CAISO		✓								
47.	Anita Lee (G4)	AESO		✓								
48.	Steve Myers (G4)	ERCOT		✓								
49.	Bill Phillips (G4)	MISO		✓								
50.	Jack Kerr	Dominion Virginia Power	✓									
51.	Michael Calimano	NYISO		✓								
52.	Ron Falsetti	IESO		✓								
53.	George Carruba	East Kentucky Power Cooperative	✓									

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G2 – MRO and JDRJC Associates
G3 – MRO Members
G4 – Standards Review Committee

Index to Questions, Comments, and Responses

1. **The revised SAR shows the Transmission Owner as an applicable entity based on the concept that there are Transmission Owners that operate control centers that could potentially have impact on the reliability of the Bulk Power System. Do you agree that the standard drafting team needs to have the flexibility to address the issue of Transmission Owners as applicable entities in the drafting of the standard**

Summary Consideration: The only negative comments received to this question were as to the inclusion of the Transmission Owner as an applicable entity. The SAR DT believes that this needs to be left to the auspices of the eventual SDT to allow them the maximum flexibility to do their job correctly. If the Transmission Owner is included by the SDT, the industry will receive their opportunity to express their opinion during the standards drafting and balloting processes. The SAR DT believes that we have responded to all of the comments.

Question #1			
Commenter	**Yes**	**No**	**Comment**
NPCC CP9		☑	Although NPCC participating members see value, from a reliability perspective, to have “large” TOs with control centers, to have back-up facilities, there is trepidation with the idea of mandating this through a NERC standard. It is more appropriate to leave the details of what TO backup facilities are necessary in the individual TOP/TO operating agreements.
Hydro-Québec TransÉnergie		☑	Although HQT see value, from a reliability perspective, to have “large” TOs with control centers, to have back-up facilities, it seems more appropriate to leave the details of what TO backup facilities are necessary in the individual TOP/TO operating agreements when a task is delegated. If a TO perform tasks that might impact the BPS, maybe they should register as a TOP.
IESO		☑	Even though we see value, from a reliability perspective, to have “large” TOs with control centers, to have back-up facilities, we are not comfortable with the idea of mandating this through a NERC standard. We strongly feel that the details of what TO backup facilities are necessary, should be dealt between the TOP and TO in their respective operating agreements.
ISO-NE		☑	Per the NERC Functional Model, the Transmission Operator operates the control centers.
Grant County PUD		☑	If a transmission owner operates a control center, they are a transmission operator. Therefore, the SAR doesn't need to address transmission owners. They just need to properly register their entity.
ITC Transmission		☑	If a Transmission Owner operates a control center, then they are a Transmission Operator. They should register as such.
Entergy		☑	It is clear that the standard would apply to the Transmission Operator. It is considerably less clear when it would apply to a transmission owner that is not also a transmission

Question #1			
Commenter	**Yes**	**No**	**Comment**
			operator. I am not aware of a case where the Transmission Owner is operating a control center and performing functions that have impact on the reliability of the Bulk Power System, but such a situation could exist. In that situation, the transmission owner might be considered to be delegated such tasks by the transmission operator or some other functional entity. My concern is that there may be some shades of gray, where it is not clear whether or not a transmission owner is required to comply with the standard.
MISO (G2)		☑	If Transmission Owner is operating a control center, this would make them a transmission operator and they should register as one.
SRC (G4)		☑	Per the NERC Functional Model, the Transmission Operator operates the control centers.
East Kentucky Power Cooperative		☑	TOs performing TOP functions should register as TOPs and would then be appropriately covered by this standard.
NYISO		☑	Per the NERC Functional Model, the Transmission Operator operates the control centers and should have sole responsibility for BPS Operation. The TOP has responsibility to ensure others who are supporting their control center, such as a TO, can do so as defined in agreements or reliability plans. A transmission owner with a conrol center that takes independent action on the BPS should be register as a TOP.
Manitoba Hydro	☑	☑	If the Transmission Owner operates a control centre then it should be registered as a Transmission Operator and meet the back up facility requirements.
ERCOT	☑	☑	If the Transmission Owner is performing tasks in accordance with a delegation agreement between the Transmission Owner and the Transmission Operator, the Transmission Operator is still responsible for meeting the requirements of the function. The delegation agreement should cover and include the relevant requirements for backup functionality of the Transmission Owner. I believe the NERC standard should show applicability to the Transmission Operator.
Dominion Virginia Power	☑		TOs (or other entities) to whom reliability tasks have been delegated should be required to have the backup facilities necessary to provide backup capabilities for those delegated tasks. Also, consideration should be given to expanding the scope to include "shared" tasks that some TOs (or other entities) are required to perform by their TOP or RC as part of a "defense in depth" strategy for monitoring and reliability analysis (for example, state estimation and contingency analysis performed by a TO at a local level to complement the "wide area" state estimation and contingency analysis performed by the RC). Also, an argument could be made that TOs (or other entities) who perform delegated or shared reliability tasks but that do not have backup facilities can be a burden on their neighbors upon loss of the capability to perform these tasks. This is because overall reliability suffers (risk goes up) when these delegated or shared tasks

Question #1			
Commenter	**Yes**	**No**	**Comment**
			are not being performed. This is especially true for TOs who supply real-time reliability data to their RC and other TOs or TOPs when loss of primary facilities causes large amounts of data to cease to be available to the data recipients. Such a loss of data exchange capability is a common cause of state estimator solution problems for data recipients.
Response: The SAR DT considered the comments above, and concluded that the SDT should have the flexibility to consider Transmission Owners, under certain circumstances where a Transmission Owner operates a control facility, as applicable entities for this standard. The comments suggest other alternatives that the SDT may also choose to consider in drafting the standard. Some of the comments suggest that if all Transmission Owners that operate control centers register as Transmission Operators then the suggested flexibility would not be necessary. The SAR DT agrees with that, but also recognizes that in the current situation the underpinning assumption that all entities operating control centers are registered that way isn't factual. Other comments suggest that this requirement can be adequately covered in delegation agreements between the Transmission Owner and Transmission Operator. The SAR DT recognizes that that may be an adequate approach, but believes the SDT should have the ability to consider whether that is an adequate approach or whether the importance of having backup capabilities warrants having an applicable standard apply directly rather than indirectly through delegation agreements. If the SDT leaves the Transmission Owner and/or Transmission Operator in the standard as applicable entities, the industry will receive their opportunity to express their opinion during the standards drafting and balloting processes.			
MRO (G3)	☑		These facilities are critical to the reliable operation of the Bulk Power system therefore flexibility to include a transmission owner as an applicable entity is reasonable.
Progress Energy	☑		
AEP	☑		
ATC	☑		
KCP&L	☑		

2. **The SAR drafting team has deleted COM-001 from the revised SAR based on the fact that COM-001 deals with generic communication issues and not backup facility issues. Communication support explicitly needed for backup facilities will be considered in the revision of EOP-008. Also, COM-001 is covered in other areas of the Reliability Standards Development Plan 2007–2009. On this basis, do you agree that COM-001 should be deleted from the scope of this SAR?**

Summary Consideration: There were no negative comments received for this question.

Question #2			
Commenter	**Yes**	**No**	**Comment**
MISO (G2)	☑		Since this SAR is dealing directly with backup capabilities, removing consideration of COM-001 makes sense. However, this causes a fundamental question. Should the standards defining primary control center capabilities include the back up capabilities as well? If so, a supplemental SAR will be required and then COM-001 would need to be considered.
Response: The SAR DT considered how the backup facility requirements would be most clearly defined and came to the conclusion that a standalone document would be best and from the recent FERC issuance of Order 693, it appears that FERC concurs. Therefore, the SAR DT does not see the need for a supplemental SAR.			
Grant County PUD	☑		EOP-008 only discusses loss of primary control facilities. No need to look at standards dealing with normal operations.
ITC Transmission	☑		
Entergy	☑		
Progress Energy	☑		
AEP	☑		
ATC	☑		
ERCOT	☑		
KCP&L	☑		
Manitoba Hydro	☑		
NPCC CP9	☑		
Hydro-Québec TransÉnergie	☑		
IESO	☑		

Question #2			
Commenter	**Yes**	**No**	**Comment**
ISO-NE	☑		
MRO (G3)	☑		
SRC (G4)	☑		
Dominion Virginia Power	☑		
NYISO	☑		
East Kentucky Power Cooperative	☑		

3. Please highlight any other changes you feel are needed before this SAR is ready to move forward to standard drafting.

Summary Consideration: The only comments requiring a response for this question refer to matters beyond the scope of the SAR DT or that have been responded to in this document.

Question #3			
Commenter	**Yes**	**No**	**Comment**
ISO-NE			There are other SARs that have been posted recently that includes reviews and potential changes to standards this SAR will impact. ISO New England believes that the Standards Committee should work to resolve multiple SARs covering the same standards to prevent confusion and potential loss of changes. It is important that these SARs are sequenced properly to ensure that there are not any lost changes.
Response: This issue is beyond the scope of the SAR DT. It is up to the SC and NERC staff to coordinate these types of issues.			
MISO (G2)			There are other SARs that have been posted recently that includes reviews and potential changes to standards this SAR will impact. For example, the Reliability Coordination (Project 2006-06) SAR will include modifications to IRO-002. This SAR should address how these changes will be coordinated with the Reliability Coordination SAR, other existing SARs and any other SAR that is expected to be proposed from the NERC Reliability Standards Work Plan.
Response: This issue is beyond the scope of the SAR DT. It is up to the SC and NERC staff to coordinate these types of issues.			
NYISO			There are other SARs that have been posted recently that includes reviews and potential changes to standards this SAR will impact. The IRC believes that the Standards Committee should work to resolve multiple SARs covering the same standards to prevent confusion and potential loss of changes. It is important that these SARs are sequenced properly to ensure that there are not any lost changes.
Response: This issue is beyond the scope of the SAR DT. It is up to the SC and NERC staff to coordinate these types of issues.			
SRC (G4)			There are other SARs that have been posted recently that includes reviews and potential changes to standards this SAR will impact. The IRC believes that the Standards Committee should work to resolve multiple SARs covering the same standards to prevent confusion and potential loss of changes. It is important that these SARs are sequenced properly to ensure that there are not any lost changes.
Response: This issue is beyond the scope of the SAR DT. It is up to the SC and NERC staff to coordinate these types of issues.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
Grant County PUD			Please change the name of the SAR from Backup Facilities to Loss of Primary Control Facilities. Revision of EOP-008 should not specify requirement for a backup control center. There are several other viable ways to maintain or resume control with a loss of primary facilities. Even if the drafters intent is correct, the title is confusing. If it is the intent of the drafters/sponsor to create a requirement for the existance of backup control centers, then a new SAR should be written that is not listed as a revision of an existing standard.
Response: The name of the present standard is "Plan for Loss of Control Center Functionality". While the SAR DT agrees with this position, it is not within the scope of the SAR DT to change the name of a SAR once it has been submitted. The actual name given to the revised standard will be addressed by the SDT.			
AEP			There should be a provision for the ability to demonstrate backup functionality if arranged/contracted with another reliability entity, as long as that entity can demonstrate their backup capability to meet the requirements and measures.
Response: This issue is beyond the scope of the SAR DT. Your comment will be passed along to the SDT.			
ATC			ATC does not support the proposed exclusion for Transmission Operators. The exclusion allows an exempt Transmission Operator to determine post event how they should continue to monitor their transmission system. The result would be an unmonitored transmission system for possibly days or months.
Response: The SAR DT made this exclusion so that very small operators who would not have an impact on the Bulk Power System would not be an applicable entity. The SDT will make the final determination on this matter.			
ERCOT			The SAR should clearly show that the backup requirements apply to the functionality rather than specifying how to do it. In other words, say they must be able to do "what" and not that they must have a backup facility (which is a "how"). This is not to say that I do not believe that backup facilities are important. They are important, and I believe it is prudent for the responsible entities to have them. However, the reliability requirement is that the responsible entity be able to perform under need.
Response: Please see the last sentence of the second paragraph of the Brief Description section of the SAR where this is specifically addressed.			
MRO (G3)			1. Remove mitigation time horizons form the SAR because they are not defined and they are not part of the Standards Development Procedure. 2. Need to specific which standards are included in this SAR to be modified other than standard IRO-002.
Response: **1.** The mitigation time horizon is a parameter of the reliability standard review guidelines that will be considered by the SDT. 2. The SAR DT has looked at the overall set of standards and feels that only IRO-002, R8 may have relevance to EOP-008.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
NPCC CP9			None.
Hydro-Québec TransÉnergie			None.
IESO			None.
KCP&L			None.
Manitoba Hydro			None.
ITC Transmission			None.
Entergy			None.
Progress Energy			None.
Dominion Virginia Power			None.
East Kentucky Power Cooperative			None.

Standard Authorization Request Form

Title of Proposed Standard	Back-up Facilities Project 2006-04
Request Date	October 26, 2006
Revised Date	April 11, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Sam Brattini	☐	New Standard
Primary Contact Sam Brattini	X	Revision to existing Standard
Telephone 215-997-4500 x270 Fax 215-997-3818	☐	Withdrawal of existing Standard
E-mail sam.brattini@us.kema.com	☐	Urgent Action

Purpose

Applicable Standards: EOP-008: Plans for Loss of Control Center Functionality

The purpose of revising these standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems — the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Consider other general improvements as described in Appendix A.
4. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in the attached review sheets.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need

As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and translations. The standard in this project is a Version 0 standard.

Detailed Description
The requirements in EOP-008 need additional specificity. The development revision to EOP-008 may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. In addition, the efforts of the OC Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008. Also, there may be backup facility requirements in some other standards, and those requirements should be considered for movement into this standard. The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational. The objective of EOP-008 should be to emphasize the continuation of functionality needed for reliable system operation regardless of the manner in which it is achieved. Additionally, consideration for communications required to explicitly support backup facilities will be included in the scope of this revision as applicable.
The reliability requirements for EOP-008 are such that simply checking the box in the Reliability Functions table for applicable functional model entities may not be appropriate. In some cases it may impose obligations on entities that are not truly warranted from a Bulk Power System reliability perspective (such as a small Transmission Operator that is only operating a radial transmission system), and at the other end it may not capture entities that are using control centers to perform critical Bulk Power System reliability tasks under delegation agreements. The basic intent is to apply this standard to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System. In concept this would include: • All Reliability Coordinators, • All Balancing Authorities, • All Transmission Operators, except those for which it is determined that loss of primary control capability would not impose a significant real-time reliability risk on the Bulk Power System • Any entity performing reliability functions as a result of delegation of tasks from any Reliability Coordinator, Balancing Authority or Transmission Operator. An example of this situation would be a transmission control center operated by an entity that is registered as a Transmission Owner but not registered as a Transmission Operator. In order to afford the standard drafting team sufficient scope coverage to consider this delegation question, Transmission Owner is also checked as being a reliability function to which the standard will apply.
Note that Appendix B is an informative attachment that contains material for consideration in the standards revision process. It should not be considered to contain mandatory changes to the standard. Comments from FERC Order 693 contained in Appendix B will be addressed by the SDT.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
X	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
IRO-002	Currently contains provisions for backup facilities.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A: Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard 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 practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

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

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **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.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Electric Reliability Organization'

Fill-in-the-Blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: Issues to be Considered

The following issues were carried over from the original industry comments on V0 standards:

- Robert Snow: (1) There needs to be a requirement on how the operating staff knows that they have lost control center functionality (system health monitor concept or equivalent functionality). (2) Under R1, the contingency plan should address how monitoring and control of facilities will be achieved and provide a maximum time for restoration of the monitoring and control functions.

The following items were gleaned from FERC Order 693:

- Backup capabilities must:
  - Be independent of the primary control center
  - Be capable of operating for a prolonged period of time generally defined by the time it takes to restore the primary control center
  - Provide for a minimum functionality to replicate the critical reliability functions of the primary control center
  - Provide that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk Power System
  - Include a requirement that all reliability coordinators have full backup control centers
  - Require transmission operators and balancing authorities that have operational control over significant portions of generation and load to have minimum backup capabilities but that they may do so through contracting for these services instead of through dedicated backup control centers

In addition to the issues cited above, the SDT must consider comments received through the SAR comment forms.

Standard Authorization Request Form

Title of Proposed Standard	Back-up Facilities Project 2006-04
Request Date	October 26, 2006
Revised Date	April 11, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Sam Brattini	☐	New Standard
Primary Contact Sam Brattini	X	Revision to existing Standard
Telephone 215-997-4500 x270 Fax 215-997-3818	☐	Withdrawal of existing Standard
E-mail sam.brattini@us.kema.com	☐	Urgent Action

Purpose

Applicable Standards: EOP-008: Plans for Loss of Control Center Functionality

The purpose of revising these standards is to:

1. Provide an adequate level of reliability for the North American bulk power systems — the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties — the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Consider other general improvements as described in Appendix A.
4. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in the attached review sheets.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Industry Need

As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards~~ and the translation of Phase III & IV planning measures~~, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards~~, Phase III & IV standards,~~ and recent updates were put in place as a temporary starting point to start up the electric reliability organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and ~~Phase III & IV~~ translations. The standard in this project is a Version 0 standard.

~~Brief~~ Detailed Description

The requirements in EOP-008 need additional specificity. The development revision to EOP-008 may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. In addition, the efforts of the OC Backup Control Center Task Force will be used as one of the inputs to the revision of EOP-008. Also, there may be backup facility requirements in some other standards, and those requirements should be considered for movement into this standard.

The definition of backup capability that is pertinent to this effort is: the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational. The objective of EOP-008 should be to emphasize the continuation of functionality needed for reliable system operation regardless of the manner in which it is achieved.

Additionally, consideration for communications required to explicitly support backup facilities will be included in the scope of this revision as applicable.

The reliability requirements for EOP-008 are such that simply checking the box in the Reliability Functions table for applicable functional model entities may not be appropriate. In some cases it may impose obligations on entities that are not truly warranted from a Bulk Power System reliability perspective (such as a small Transmission Operator that is only operating a radial transmission system), and at the other end it may not capture entities that are using control centers to perform critical Bulk Power System reliability tasks under delegation agreements.

The basic intent is to apply this standard to any entity for which the loss of its primary control capability would impose a significant real-time reliability risk to the Bulk Power System. In concept this would include:

- All Reliability Coordinators,
- All Balancing Authorities,
- All Transmission Operators, except those for which it is determined that loss of primary control capability would not impose a significant real-time reliability risk on the Bulk Power System
- Any entity performing reliability functions as a result of delegation of tasks from any Reliability Coordinator, Balancing Authority or Transmission Operator. An example of this situation would be a transmission control center operated by an entity that is registered as a Transmission Owner but not registered as a Transmission Operator. In order to afford the standard drafting team sufficient scope coverage to consider this delegation question, Transmission Owner is also checked as being a reliability function to which the standard will apply.

Note that Appendix B is an informative attachment that contains material for consideration in the standards revision process. It should not be considered to contain mandatory changes to the standard.

Comments from FERC Order 693 contained in Appendix B will be addressed by the SDT.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
X	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
IRO-002	Currently contains provisions for backup facilities.

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A:

Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard 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 practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

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

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **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.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Electric Reliability Organization'

~~Bulk Electric System~~

~~Replace, 'Bulk Electric System' with 'bulk power system'~~

Fill-in-the-~~b~~Blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: Issues to be Considered~~EOP-008 Technical Issues List~~

~~Excerpted from NERC Reliability Standards Development Plan: 2007 - – 2009~~The following issues were carried over from the original industry comments on V0 standards:

- Robert Snow: (1) There needs to be a requirement on how the operating staff knows that they have lost control center functionality (system health monitor concept or equivalent functionality). (2) Under R1, the contingency plan should address how monitoring and control of facilities will be achieved and provide a maximum time for restoration of the monitorin and control functions.

The following items were gleaned from FERC Order 693:

- Backup capabilities must:
  - Be independent of the primary control center
  - Be capable of operating for a prolonged period of time generally defined by the time it takes to restore the primary control center
  - Provide for a minimum functionality to replicate the critical reliability functions of the primary control center
  - Provide that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk Power System
  - Include a requirement that all reliability coordinators have full backup control centers
  - Require transmission operators and balancing authorities that have operational control over significant portions of generation and load to have minimum backup capabilities but that they may do so through contracting for these services instead of through dedicated backup control centers

In addition to the issues cited above, the SDT must consider comments received through the SAR comment forms.

~~**Standard Review Form**~~ ~~**Project 2006-04 Back-up Facilities**~~		
~~**Standard #**~~	~~**EOP-008-0**~~	~~**Comments**~~
~~**Title**~~	~~Plans for Loss of Control Center Functionality~~	~~Okay but could probably drop 'Plans for'.~~
~~**Purpose**~~		~~Okay~~
~~**Applicability**~~		~~Isn't the reliability entity the TSP and not the TO as per the FM?~~
~~**Requirements**~~	~~*Conditions*~~	~~Okay~~
	~~*Who?*~~	~~Okay~~
	~~*Shall do what?*~~	~~Grammar error in R1.2~~
	~~*Result or Outcome*~~	~~Missing~~
~~**Measures**~~		~~Measure doesn't define required evidence.~~
~~**To Do List**~~	~~FERC NOPR~~ ~~oInclude a Requirement that all reliability coordinators have full backup control centers since they are essential to Bulk-Power System reliability.~~ ~~oProvision for backup capabilities should be an explicit Requirement. Such backup capability, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time; and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.~~ ~~FERC staff report~~ ~~oDistinction between providing plans and proving capabilities~~ ~~oIndependence from primary control center~~ ~~Regional Fill-in-the-Blank Team Comments~~ ~~oNo comments~~ ~~V0 Industry Comments~~ ~~oHow does staff know control center is lost?~~ ~~oHow is backup control achieved?~~ ~~oMax. time to restore capabilities~~ ~~VRF comments~~ ~~oR1 - Not having a written plan does not directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading~~ ~~oR1.1 - Not having a written plan is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.~~	

Please return this form to sarcomm@nerc.net by **May 11, 2007** with "Backup SDT Nomination" in the subject line. For questions, please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net.

Note that this drafting team will meet on June 21 (8 a.m. to 5 p.m.) and Friday, June 22 (8 a.m. to noon) in Syracuse, New York.

Name:	
Organization:	
Address:	
Office Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the Backup Facilities Standard Drafting Team. Prefer candidates with expertise in specifying facilities or in developing backup control center plans or participation as a member of the Operating Committee's Backup Control Center Task Force. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):		**I represent the following Industry Segment (check one):**
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs, ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations and Regional Entities

Which of the following Function(s)[1] do you have expertise or responsibilities:	
☐ Reliability Coordinator	☐ Transmission Service Provider
☐ Balancing Authority	☐ Transmission Owner
☐ Interchange Authority	☐ Load Serving Entity
☐ Planning Coordinator	☐ Distribution Provider
☐ Transmission Operator	☐ Purchasing-selling Entity
☐ Generator Operator	☐ Generator Owner
☐ Transmission Planner	☐ Resource Planner
	☐ Market Operator
Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.	
Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the Functional Model, which is downloadable from the NERC Web site: http://www.nerc.com/~filez/functionalmodel.html

Maureen E. Long
Standards Process Manager

April 30, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement
Nomination Period Opens for Standard Drafting Team

The Standards Committee (SC) announces the following standards action:

Nominations for Project 2006-04 Backup Facilities Standard Drafting Team (April 30–May 11, 2007)

The Standards Committee is seeking industry experts to serve on the Backup Facilities Standard Drafting Team. This drafting team will work on the modification of the following standard:

EOP-008 — Plans for Loss of Control Center Functionality

If you are interested in serving on this standard drafting team, please complete this nomination form and return it to sarcomm@nerc.net by May 11, 2007 with "Backup SDT Nomination" in the subject line. The first meeting of the team will be held in Syracuse, New York from 8 a.m. until 5 p.m. on June 21 and from 8 a.m. until noon on June 22, 2007.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 4Q08. The current draft is the first iteration of the revision of the existing standard EOP-008. Violation Risk Factors, Time Horizons, Measures, Compliance, and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard.	April 2008
2. Submit first revision of standard.	May 2008
3. Respond to comments from second posting of standard.	July 2008
4. Submit second revision of standard.	July 2008
5. Submit standard for balloting.	September 2008
6. Submit standard for recirculation balloting.	October 2008
7. Submit standard to BOT.	November 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits (IROLs).

   4.1.3. Balancing Authority.

5. **Effective Date:** TBD

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have an Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This Operating Plan for backup functionality shall include the following at a minimum:

R1.1. The location and method of implementation for providing backup functionality.

R1.2. A high level overview of the elements required to support the backup functionality. These elements shall include, at a minimum:

R1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES.

R1.2.2. Data communications.

R1.2.3. Voice communications.

R1.2.4. Power source(s).

R1.2.5. Physical and cyber security.

R1.3. An Operating Process for keeping the backup functionality current with the primary control center.

R1.4. Operating Procedures for use in determining when to implement the Operating Plan for backup functionality including, at a minimum:

R1.4.1. Criteria for evacuation of the primary control center including the decision authority for initiating the Operating Plan for backup functionality and the Operating Process for initiation of backup functionality.

R1.4.2. Criteria for returning operations support to the primary control center including the decision authority and the Operating Process for returning to the primary control center.

R1.5. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running.

R1.6. Identification of the roles for all involved personnel during the initiation and implementation of the Operating Plan for backup functionality and for the return to the primary control center.

R2. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a copy of its Operating Plan for backup functionality located in its primary control center and at the location supporting backup functionality.

R3. Each applicable Transmission Operator directing BES operations through other entities shall include those operations in its Operating Plan for backup functionality.

R4. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another Reliability Coordinator's primary control center) that replicates the functionality of its primary control center facility as required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

R5. Each Balancing Authority and applicable Transmission Operator shall have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.

R6. Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.

R7. Each Balancing Authority and applicable Transmission Operator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than six hours

R8. For each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations.

R8.1. For each applicable Transmission Operator, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the situational awareness and control of facilities with defined Interconnection Reliability Operating Limits (IROLs) beyond the two hour time period.

R8.2. For each Balancing Authority, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the calculation and control of its ACE beyond the two hour time period.

R9. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall have its Operating Plan for backup functionality reviewed and approved annually by a manager.

R9.1. The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or communication protocols.

R10. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for any aspect of its operation.

R11. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that is capable of operating for an indefinite period of time.

R12. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall test its Operating Plan for backup functionality through actual implementation or test operations for a minimum of two hours annually.

R13. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that anticipates that a total loss of primary or backup capability will last for more than six calendar months, shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☐ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☐ No

   Comments:

Standards Announcement

Comment Period Opens
February 7–March 7, 2008

Now available at: http://www.nerc.com/~filez/standards/Backup_Facilities.html

Comment Period for Project 2006-04 — Backup Facilities Opens February 7, 2008

The Backup Facilities Standard Drafting Team has completed its first draft of a set of proposed requirements for EOP-008-1 — Loss of Control Center Functionality. The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable.

The drafting team has made many significant changes to this "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The drafting team wants stakeholder feedback on the requirements before developing the measures and compliance elements of the standard.

Please use this comment form to submit comments on the draft standard.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	William J. Smith	
Organization:	Allegheny Power	
Telephone:	724.838.6552	
E-mail:	wsmith1@alleghenypower.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: All control centers (Generator Operator or Transmission Owner (LCC) that control facilities via an EMS, GMS, etc. should comply with a Backup Facility criteria. That criteria may be in the form of a NERC Standard or a set of RTO/ISO requirements. In the case where a set RTO/ISO requirements are used for control centers that are not Transmission Operators, those requirements should meet a minimum criteria established in a NERC Standard to guarentee uniformity on Bulk Electric System.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: See comment to question #1

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: See comment to Question #4

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: The difference in the transition time frame for the RC compared to the TOP and BA would seem to indicate that the loss of the functions of the RC are deemed to be more critical to the reliablity of the BES than the the loss of the functions conducted by the TOP and BA. To the contrary, it is most likely that the RC functions are dependant on the data supplied from a TOP or BA. The loss of the TOP or BA primary facility could deprive the RC of critical information. A 2-hour transition time seems appropriate for all three entities.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: A 2 hour test would most likely not be long enough to test all the functions that occur in a routine day. A minimum time requirement makes less sense than requiring that all functions required to be conducted during a normal day be tested.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: The RC, TOP, or BA that losses it's primary or back-up control center should notify it's Regional Entity and neighboring entities within 24 hours. Within that 24 hour period, that entity should provide a plan that would outline how the loss of the remaining facility would be handled. There should always be a plan for the next contingency. A plan to re-establish a lost facility is less important that providing a plan to handle the loss of the remaining facility.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☒ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jason Shaver	
Organization:	American Tranmission Company	
Telephone:	262 506 6885	
E-mail:	jshaver@atcllc.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "BF Standards" by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: ATC does not understand the SDT's motivation for limiting the scope of the proposed Standard to Transmission Operators (TOPs) with control of Facilities that are desigated as Critical Assets or with defined Interconnection Reliability Operating Limits. The proposed accountability is a step backward from existing Reliability Standards and has the potential to expose the grid to greater reliability related risks following the loss of a non-applicable TOP's control center.

   What justification does the SDT provide to make such a major change to this reliability standard?

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: Generation is critical to the reliable operation of the BPS and should be included. ATC believes that the a more appropriate exemption could be based on the MW controlled by the GOP.

   ATC may be open to changing its position on this issue if strong information is presented to support this position.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: The proposed standard is weaker than the existing standard. ATC believes that the expected time should be one hour and, if exceeded, the plan should address how you are going to operate into the next hour. With a maximum time of 2 hours.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: Should be the same as requirement 6.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments: The two hour testing is appropriate.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Six months is an excessive amount of time to have a plan for re-establishing backup capability. ATC belives that three months is a more appropriate amount of time.

Why does the SDT believe that six months is needed in order to develop a plan for re-establisting backup capability? ATC would say that establishing backup capability may take more than six months but to develop a plan should not take six months.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☐ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: The standard introduces three new capitalized terms that are not defined in the Standard:
Operating Plan, Operating Process and Operating Procedure.

ATC does not agree with the creation of the three new terms and believes that the terms should be replaced with a more general statement; i.e. "plan, process or procedure" as follows:

R1:
Each RC, BA and TOP shall have a plan, process or procedure describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This plan, process or procedure for backup functionality shall include the following:

R1.3

The plan, process or procedure shall document how the entity will maintain backup functionality current with the primary control center.

R1.4

The plan, process or procedure shall document how the decision for implementation is to be made:

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Crystal Musselman	
Organization:	Avista Corporation	
Telephone:	(509) 495-4083	
E-mail:	crystal.musselman@avistacorp.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: Change to 12 calendar months for a plan. Need wording to indicate you are specifically exempt from EOP-008 for a time period (24-36 months) for rebuilding your control center.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: R8 requires further clarification.

   R9 - Requirement 9 should be moved under Requirement 1. The relation between the annual review and approval and the 60-day update and approval is not clear.

   R9.1 clarify to indicate "changes that effect the operating plan."

   R10 remove - basically a restatement of R4. Additionally "...any aspect of the operation." encompases aspects that would not be related to the reliability of the system but would ba an aspect of the operation (i.e. filling out time sheets).

   R11 - remove - This requirement seems to be in conflict with the purpose of R1 and R13.

   R13- Recommed that this be changed to 1 year. If this actually happened, there will be other issues to consider which may be very complex and trying to make this decision in 6 months may apply undue pressure on the decision. We recommend exemption from EOP-008 until the completion of a plan to reestablish backup capability.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	J. Andrew Dodge / William Keagle / Ed Carmen	
Organization:	Baltimore Gas and Electric Company	
Telephone:	410-597-7289	
E-mail:	edward.j.carmen@bge.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: Under the Applicability Section 4.1.2; What is the official definition of "Critical Assets"? Are these the same as the Critical Assets identified in the CIP-002? There are situations where the Transmission Operators and the Transmission Owners are not the same entitiy. In this case, the Transmission Owner is responsible for identifying their Criitical Assets under CIP-002 and there is no requirement that they share this list with their Transmission Operator. In this relationship, how would the Transmission Operator know what the Critical Assets are in their transmission zone?

   Does the statement "with control of Facilities that are designated as Critical Assets" imply that this standard does not apply to Transmission Operators that do not have physical control of Facilities that are designated as Critical Assets?

   As written, this standard would not apply to Transmission Owners who perform the Local Control Center function under the direction of a NERC registered Transmission Operator (although the LCC may actually control the facility designated as critical or associated with the IROL).

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: If greater than 2 hours, only if their plan includes processes that will ensure the situational awareness and control of facilities. We are unclear as to how this can be accomplished without someone physically being at the backup control center within the initial 2 hour period.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: The requirement should state that all operating personnel should operate real-time at the backup facility for a minimum of 1 shift per year in order to stay proficient with the transistion plan and the operations at the backup facility. This also provides more thourogh testing of the equipment at the backup facility when the center is utilized for real-time operations.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: What does "have a plan in place for re-establishing backup capability" mean? Does this mean a) - that the requirement is to have a plan to establish backup capability or b) - is the requirement to re-establish backup functionality within 6 months? If a) is the intent, 6 months is too long to only develop a plan. A temporary backup solution should be required much sooner than 6 months.

   As written, R13 is not clear. Need to clarify R13 requirement. It is not clear that the RC, BA, and TO need to supply the backup plan 6 months PRIOR to the anticipated date that they expect the primary or backup control center to be inoperable. As stated, it could be supplied 6 months after the date that the functionality is lost.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: R1.6 identification of roles for ALL involved personnel may be too prescriptive. Thinking of all the scenarios for a loss of control center, certain individuals may be playing different roles. We think it should say, "all operations personnel" rather than "all involved" to limit the scope of pre-defined roles so that individuals such as support personnel can be used to the maximum effectiveness.

As written, R3 is not clear. Need to clarify the R3 requirement. It is not clear how the standard applies to those other entities that perform the BES Operations.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	TERRY DOERN	
Organization:	BONNEVILLE POWER ADMINSTRATION	
Telephone:	360-418-2341	
E-mail:	TLDOERN@bpa.gov	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments: If TOs have IROLs they must have the capablity to monitor critical lines & transmission paths within critical time periods (20 minute for stability, 30 minutes for thermal). This may add the need for B/U control center.
   Many smaller TOs with limited tranmission do not impact the BES.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: A GOP must provide support to the BA to meet BAL standards during adverse power system conditions even when their primary control center is destroyed or not funcational. Other options may be practical as long as they meet the reliablity needs and meet NERC and regional standards.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: For quiet periods of operation, 2-6 hours is adequate. However for challenging times (peak loads, storms, loss of major generation, operating near IROL or SOL limits) 2 hours is insufficient. In 2003, a company did not have situational awareness visibility for 30-60 minutes with very adverse consequences. NERC, the SDT and NERC entities should consider these adverse situations occuring during loss of control center. Could recent disturbances this month be managed during the transition to their current backup control center?

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: One specific change - "power sources" such as engine generators and UPS should be tested more often, weekly or monthly. In disturbances, control center EGs and UPS are often problematic.

   Also, if the backup software systems must be up to date as mentioned in R1.3 how does a BA or TO know without testing?

   Change the language to "adequately test all functions of the backup control center that are needed to replace the primary control center operation." For example:

   - test AGC for two hours annually, or when changes that impact operation

   - test voltage control for two hours.

   - test power sources EG/UPS monthly

   NERC CIP standards have requirements more frequent than annually that apply to backup control centers.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: Having a plan in place within six months is reasonable if this includes getting budget approval for replacement. Having it functional within six months may prove difficult. EMS vendors have said they can complete a project in about 12-18 months. NERC should suggest or require that the backup be functional again in a specific time period such as 18-24 months after failure of the primary control center.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments: I don't know of any regional variation.
   However, for some BAs & TOPs, operating Special Protection Schemes is a critical issue for reliablility of the Bulk Electric System that may require a robust control center and backup control center. Additional requirements may be needed for managing SPS during all adverse power system conditions including loss of control center.

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

☐ No

Comments:
This is a good improvement for EOP-008.

if a BA or TOP has a "hot" back up site that is staffed 24/7,
less prescribed testing or documentation is needed.

R1.3 - add a timeline to keep current, weekly or monthly. Daily would be to difficult.

R5 - "includes monitoring, control, logging, and alarming sufficient for
maintaining compliance with all Reliability Standards applicable to BA & TO" .
ALL Reliability Standards is too broad.
An extreme example: Do we need monitoring of vegetation management at the backup control center? No.   BAL standards for BAs - Yes.
Prepare a list of standards/requirements we must meet from the B/U site.

R10 language "backup capability that does not depend on the primary control center for any aspect of its operation" may force companies to buy a development system for the backup site. An EMS vendor may be able to provide development system on a temporary basis.
Change "any aspect of its real time operation"

R13 - Add a specific schedule for completion of backup control center functionality in addition to a plan. 2 years is reasonable.

Will utilities still be liable for sanctions and penalities during loss of control center incidents and especially the 2-6 hour transition? Please have NERC comment. This may change the business case for backup control center.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	John Appel	
Organization:	Chelan County PUD	
Telephone:	(509) 661-4705	
E-mail:	john.appel@chelanpud.org	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☒	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "BF Standards" by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: Our generation facilities do have procedures for maintaining operations in the event of a loss of control system functionality, however this does not involve relocating to different facilities.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: 2 hours is a long time to be without a Reliability Coordinator function in the case of an emergency. I believe WECC plans to have the two Reliability Coordinators be a backup for each other with duplicate capabilities.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: 6 hours is a long time, however I know that some utilities have to travel long distances to their backup control center. It is difficult to imagine a scenario where we wouldn't be able to be up and running in less than 1 hour.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: 6 months to develop a plan? No timeframe to have lost control facilities operational? Why have a requirement? Perhaps developing a plan in 3 months or less and demonstrating progress according to schedule to restore lost control functionality - or something like that.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: We suggest the following for R10: Replace "for any aspect of its operation" with "any functionality required to maintain compliance with all applicable reliability standards".

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Eduardo Paredes González	
Organization:	CFE	
Telephone:	011-52-686-558-15-02	
E-mail:	eduardo.paredes@cfe.gob.mx	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments: As long as the requirements in this standard are applicable to any transmission operator whose systems can impact reliability of the BES and not just registered TOPs.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: Because Reliability Coordinators have to be as soon as possibly ready to coordinate the diferents Control Areas

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments: If the assumption applies to the implementation or testing operations of the backup center and not each individual.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments: 6 months is reasonable and makes its clear of the requirement that has not been available in the past.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments: Not aware of any at this time

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☐ Yes

☒ No

Comments:

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jack Kerr	
Organization:	Dominion Virginia Power	
Telephone:	804-273-3393	
E-mail:	jack.kerr@dom.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "BF Standards" by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: Dominion Virginia Power (DVP) believes that requirement 4.1.2, as written, is unenforceable and unmeasurable. There may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs. Alternatively ,there is a process to request waivers from NERC standards that could be used to solve this issue.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: DVP agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). DVP believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets.

   Other reasons for not including GOP's in this standard are:

   1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area.
   2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and
   3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: The term 'transition period' is ill-defined by the parenthetical expression that follows it. This leaves us unable to render an opinion. The parenthetical expression included in R6 should be broken out, more precisely defined, and placed in the standard as a measure for R6.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: DVP believes R8.1 and R8.2 are not appropriate subrequirements of Requirement 8 since they pertain to required functionality in the transition period while R8 pertains to a requirement for a notification list. We also believes that all functional entities subject to this standard in its current form should have a two hour transition period. As currently written, R8.1 and R8.2 are essentially unmeasureable.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: DVP believes that R12 is more appropriate as a measure for R6, and the number of required hours to test the plan is immaterial to reliability.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: This requirement is construed as attempting to give an entity an automatic waiver from R1 through R12 of this standard, following a catastrophic loss of its primary or backup control center (BUCC) that is a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC?

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: 1) There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the definition of what starts the transition period and what ends the transition period to the backup control center should be included in the standard.

   2) Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure?

   3) Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up.

   4) A general comment is that this standard, taken as a whole, appears to include "how" language. Requirements should be limited to "what" is required. Much of what is included in this standard appears to be "good utility practice" and not reliability requirements and should be stripped from the standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization: .		
Telephone:		
E-mail:		
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**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: Electric Market Policy

Lead Contact: Jalal Babik

Contact Organization: Dominion Resource Services, Inc

Contact Segment: 3,5

Contact Telephone: 804-273-4109

Contact E-mail: Jalal.Babik@dom.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Louis S. Slade, Jr.		**RFC, SERC**	3,5
Ronald E Hart		NPCC, MRO	3,5

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: We support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG). They stated that they "believe that requirement 4.1.2, as written, is unenforceable and unmeasurable. There may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs. Alternatively ,there is a process to request waivers from NERC standards that could be used to solve this issue."

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: In Order 693, FERC stated that the goal of the Reliability Standard is the continuation of reliable operations and the maintenance of situational awareness in the event that the primary control center is no longer operational. They further stated that "Other entities, including balancing authorities, transmission operators and centrally dispatched generation control centers, must provide for the minimum backup capabilities discussed above but may do so through other means, such as contracting for these services instead of through dedicated backup control centers." Given that the impact to reliability can vary depending on many diverse factors including; size of owner's asset base, NERC region, ISO/RTO or market rules, etc. we support the standard as written. Each region can, through its standards development process, place additional requirements if it deems necessary. Each RTO/ISO or market, through its stakeholder process, can also impose additional requirements upon its participants if it deems necessary. We further state that we support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG).

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

Comments: We support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG). They stated "The term 'transition period' is ill-defined by the parenthetical expression that follows it. This leaves the SOCSRG unable to render an opinion. The parenthetical expression included in R6 should be broken out, more precisely defined, and placed in the standard as a measure for R6."

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: We support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG). They stated "The SOCSRG believes R8.1 and R8.2 are not appropriate subrequirements of Requirement 8 since they pertain to required functionality in the transition period while R8 pertains to a requirement for a notification list. The SOCSRG also believes that all functional entities subject to this standard in its current form should have a two hour transition period. As currently written, R8.1 and R8.2 are essentially unmeasureable. "

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: We support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG). They stated "The SOCSRG believes that R12 is more appropriate as a measure for R6 and the number of required hours to test the plan is immaterial to reliability "

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: We support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG). They stated "This requirement is construed as attempting to give an entity an automatic waiver from R1 through R12 of this standard, following a catastrophic loss of its primary or backup control center (BUCC) that is a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC?

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: We support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG). They stated "There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the definition of what starts the transition period and what ends the transition period to the backup control center should be included in the standard.

Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure?

Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up.

A general comment by the SOCSRG that this standard, taken as a whole, appears to include "how" language. Requirements should be limited to "what" is required. Much of what is included in this standard appears to be "good utility practice" and not reliability requirements and should be stripped from the standard.

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Daniel Herring	
Organization:	Detroit Edison Company	
Telephone:	313-235-5365	
E-mail:	herringd@dteenergy.com	
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**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: Detroit Edison Company

Lead Contact: Daniel Herring

Contact Organization: same

Contact Segment: same

Contact Telephone: same

Contact E-mail: same

Additional Member Name	Additional Member Organization	Region*	Segment*
Don Boyer	Detroit Edison Company- Merchant Operations Center		

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "BF Standards" by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: I do not agree with this limitation. I would agree with this aproach if there was one risk-based assessment methodology used by all Transmission Operator entities to identify their Critical Assets.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: As energy markets mature and more generation assets are operated from central control centers, it is imperative for grid reliability, security, and stability that GOPs be able to fulfill their roles. Not having GOPs identified as applicable entities to a reliability standard addressing loss of control center functionality misses the intent of this standard.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☒ Yes

   ☐ No

   Comments: Previously identified FERC Order 693.

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: We would recommend that language for annual training for the operating personnel be included in the standard with a walkthrough and start up of the facility being the minimum.

   We feel the six calendar month language in R13 is to long of a time period.

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Greg Rowland	
Organization:	Duke Energy	
Telephone:	704-382-5348	
E-mail:	gdrowland@dukeenergy.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☒ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: The limitation doesn't make sense and would be difficult to enforce, since Critical Asset lists and defined IROLs will change over time. Applicability should be on the basis of NERC Registration, to avoid an ongoing tangled mass of exceptions. For example, a TOP with control over a limited number of facilities should still be required to provide backup functionality, however backup functionality can be provided in other ways than constructing backup facilities.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: As FERC noted in Order No. 693, generator operators who have operational control over significant amounts of generation are important to the reliability of the Bulk Power System. As such they should provide backup capabilities that are independent of the primary control center, can operate for a prolonged period of time, and provide for a minimum functionality to replicate the critical reliability functions of the primary control center. The reason BAs are required to have backup functionality is that BAs have direct communications (both data and voice) with generator sites and generator personnel. These are the front lines of operational situations. It is vital that we maintain these links in both normal, emergency conditions, and backup mode conditions.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: 2 hours may be reasonable, however R6 is an ambiguous requirement. It is unclear exactly what the 2-hour transition period is referring to. It may not always be possible to establish an exactly precise point in time when primary control center functionality was lost. Likewise, it may not always be possible to define an exact point in time when backup functionality is "up and running". Furthermore, it is unclear whether this is just a requirement to have an appropriate 2-hour plan, or whether it is a requirement to always meet the 2-hour time limit, whether for tests or actual activation.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: 6 hours is far too long to get backup functionality up and running. TOP's and BA's should be on the same 2-hour clock as the Reliability Coordinator. TOPs and BAs have direct communications to field locations and personnel that are critical under normal and emergency conditions. Many RCs do not have this capability and depend on TOPs and BAs to provide this link to the capability on the ground.

   See response to Comment #3 above. While we believe 2 hours may be reasonable, R7 like R6 is an ambiguous requirement. It is unclear exactly what the transition period is referring to. It may not always be possible to establish an exactly precise point in time when primary control center functionality was lost. Likewise, it may not always be possible to define an exact point in time when backup functionality is "up and running". Furthermore, it is unclear whether this is just a requirement to have an appropriate plan, or whether it is a requirement to always meet the time limit, whether for tests or actual activation.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: A single test of 2 hours duration annually is of very limited value for system operators and the backup functionality. This significantly limits the number of system operators who experience backup control, but more importantly minimizes the capability testing of the backup control functionality. This is a very low hurdle. This requirement is also silent on backup control functionality training. Specific training should be included in the training standards.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: This requirement seems reasonable, but needs more clarity. If the view of this requirement is that backup capability must be re-established within 6 months of the loss of primary functionality, we question whether it can done, particularly in situations where the primary capability is totally destroyed. Furthermore, while an entity is in the backup facility, perhaps for 6 months or longer while the primary facility is being restored, there should be a clear exemption from having a "backup for the backup", since the need for such a facility would be a very low probability event. Similarly, if more than one entity plans to utilize the same backup facility they should not be found non-compliant when another entity is utilizing the facility. The SDT should provide more clarity and specificity around the exceptions from requirements in the standard for these types of situations.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: The Purpose statement of this standard focuses on an event in which a control center becomes inoperable. Requirements then focus on providing "backup functionality" for a loss of primary control center functionality. The focus of the standard should be tightened up so that it is clear that entities are required to provide backup functionality that addresses loss of primary control center functionality.

R10 requires that backup capability cannot depend on the primary control center for any aspect of its operation. This standard should more specific regarding how far “out” into the communications network infrastructure entities must assume the primary facility functionality reaches, for the purpose of establishing backup functionality.

R11 states that the backup capability must be capable of operating for an indefinite period of time. It's unclear how compliance will be determined for this requirement.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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: Entergy Services, Inc. System Planning & Operations (Generation)

Lead Contact: Will Franklin

Contact Organization: Entergy

Contact Segment: 6

Contact Telephone: 281-297-3594

Contact E-mail: wfrankl@entergy.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Jerry Stout	Entergy	SERC	6

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: The attempt to limit the Transmission Operators subject to this standard opens many more questions and issues that are not addressed. The argument could also be made by some BAs that they have no critical assets or other reliability impact and thus desire an exclusion.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: It appears to be appropriate to exclude centrally dispatched control centers for generators if they do not perform the functions of or part of the functions of a BA. The means for executing dispatch for a unit is a business decision If the dispatch operator is not performing any BA functions then there is no need for this standard to apply and whatever other standards or rules for maintaining communication between the unit and BA would apply.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. A statistical risk analysis would be ideal to determine this allowable time, if a valid model exists. If an arbitrary value is used, then an industry survey or something similar (experts/EPRI) may be appropriate.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

☒ No

Comments: It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. A statistical risk analysis would be ideal to determine this allowable time, if a valid model exists. If an arbitrary value is used, then an industry survey or something similar (experts/EPRI) may be appropriate

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☒ No

Comments: It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. Otherwise, the testing should be of adequate length to test the back up functions, whether it be 30 minutes or 12 hours would be dependent upon the entity's desires.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments:

Recommend a shorter time time frame such as within 30 days, and updated every 30 days until back up capability is restored. 6 months is too long for an entity to not have a plan for continuing operations if its primary or back up facility are unavailable. The plan itself may take longer than 6 months to complete.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments:
Consider adding provisions for short term planned and unplanned outages on either the primary or back up control center. This would be similar to outage "time clocks" in the nuclear world. This would allow entities to make repairs, upgrades on the primary and back up control centers without automatically being non-compliant when conducting such activities.

An example might be that the primary or back up control center not be unavailable (definition needed?) for more than 7 cumulative days per quarter. Exceptions may be granted by the Regional Compliance Enforcement Authority.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Ed Davis	
Organization:	Entergy Services	
Telephone:	504-576-3029	
E-mail:	edavis@entergy.xom	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: Entergy agrees with and supports the SOCRG comments. The SERC Operating Committee Standards Review Group (SOCSRG) believes that requirement 4.1.2, as written, is unenforceable and unmeasurable. There may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs. Alternatively ,there is a process to request waivers from NERC standards that could be used to solve this issue.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: Entergy agrees with and supports the SOCRG comments. The SOCSRG agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets.

   Other reasons for not including GOP's in this standard are:

   1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area.
   2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and
   3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: Entergy agrees with and supports the SOCRG comments. The term 'transition period' is ill-defined by the parenthetical expression that follows it. This leaves the SOCSRG unable to render an opinion. The parenthetical expression included in R6 should be broken out, more precisely defined, and placed in the standard as a measure for R6.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: Entergy agrees with and supports the SOCRG comments. The SOCSRG believes R8.1 and R8.2 are not appropriate subrequirements of Requirement 8 since they pertain to required functionality in the transition period while R8 pertains to a requirement for a notification list. The SOCSRG also believes that all functional entities subject to this standard in its current form should have a two hour transition period. As currently written, R8.1 and R8.2 are essentially unmeasureable.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Entergy agrees with and supports the SOCRG comments. The SOCSRG believes that R12 is more appropriate as a measure for R6 and the number of required hours to test the plan is immaterial to reliability

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Entergy agrees with and supports the SOCRG comments. This requirement is construed as attempting to give an entity an automatic waiver from R1 through R12 of this standard, following a catastrophic loss of its primary or backup control center (BUCC) that is a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC?

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: Entergy agrees with and supports the SOCRG comments. There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the definition of what starts the transition period and what ends the transition period to the backup control center should be included in the standard.

Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure?

Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up.

A general comment by the SOCSRG that this standard, taken as a whole, appears to include "how" language. Requirements should be limited to "what" is required. Much of what is included in this standard appears to be "good utility practice" and not reliability requirements and should be stripped from the standard.

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Sam Ciccone
Organization:	FirstEnergy Corp.
Telephone:	(330) 252-6383
E-mail:	sciccone@firstenergycorp.com

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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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*
Doug Hohlbaugh	FE	RFC	
Dave Folk	FE	RFC	
John Reed	FE	RFC	
Eugene Blick	FE	RFC	
John Stephens	FE	RFC	
Steve Lux	FE	RFC	
Bob Chambers	FE	RFC	

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: We do not agree with the limitations proposed in the applicability. We see the following reliability issues with these limitations:
   1. It leaves it to the TOP to determine if the standard applies to him. The burden of determining applicability to these requirements should be the responsibility of the auditor.

   2. If a TOP incorrectly determines that he is not responsible to have plans for backup functionality, his neighbors in the BES control system may be in jeopardy.

   3. If an entity is registered as a TOP, then every standard applies to him since his registration has already determined he has impact on the reliability of the Bulk Electric System.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: We do not agree with the exclusion of a GOP with a centrally dispatched control center from the applicable entities in this standard. GOPs with responsibility for many units play an important role in the reliable operation of the BES. These GOPs should have business continuity plans. The bottom line is this: If it is a control center, and it has impact on the BES, it must be responsible for providing a way to backup its control center.

   We suggest adding the "Generator Operator" to the Applicability section of the standard, and adding "Generator Operator with centrally dispatched control centers" to requirements R1, R2, R5, and R7 through R13.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

☒ No

Comments: We suggest allowing provisions if the transition time takes longer than 2 hours. Similar to the current requirement for transition time from EOP-008-0 Requirement R1.8, we suggest rewording R6 as follows: "Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours. Interim provisions must be included in the plan when extenuating circumstances cause the transition to take longer than two hours."

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: We do not agree with the "6-hour" time frame. Also, we suggest allowing provisions if the transition time takes longer than 2 hours. Similar to the current requirement for transition time from EOP-008-0 Requirement R1.8, we suggest rewording R7 and R8 as follows [rewording also includes GOP with centralized dispatched control center based on our comments from Question #2]:

R7: "Each Balancing Authority, Transmission Operator, and Generator Operator with a centrally dispatched control center shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is no more than one hour. Interim provisions must be included if it is less than two hours. Interim provisions must be included in the plan when extenuating circumstances cause the transition to take longer than two hours."

For R8, we suggest rewording as follows: "For each Reliability Coordinator, Balancing Authority, Transmission Operator, and Generator Operator with a centrally dispatched control center, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations.

R8.1 & R8.2 - We believe that these requirements are not necessary. Requirement R1.5 already includes requirements for the transition period while backup functionality is obtained. We suggest removing these requirements.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: We agree with testing is very important. We also think that it is important enough that it should be performed more frequently and longer each time. We suggest a change from "two hours annually" to "four continuous hours semi-annually".

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments:
1. Operating Plan, Operating Process, Operating Procedure - Some entities may use a combination of these documents or simply specific procedures or "steps" to ensure reliable backup functionality. The specific use of a Plan, Procedure, or Process may put additional burden on an entity to maintain additional and unnecessary documentation. Also, the use of all these terms make the wording awkward and degrade the readability of the standard. Therefore we suggest that anywhere an Operating Plan, Process or Procedure is required in this standard, that it simply states either a "plan" (note: small caps] or "steps required" that an entity be required to adhere to.

If the SDT is bound to the use of the capitalized NERC terms, then, for flexibility, we suggest that anywhere an Operating Plan is required, that entities be allowed to provide an Operating Process or Operating Procedure as an alternative. Also, we suggest that anywhere an Operating Process is required, that an entity be allowed to provide an Operating Procedure as an alternative. We suggest an across the standard change from:

a. "Operating Plan" to "Operating Plan, Operating Process, or Operating Procedure". [As an example of a precedent to using all three terms, see standard IRO-014-1 Requirement 1] b: "Operating Process" to "Operating Process or Operating Procedure"

2. R1.2 - Suggest removing the phrase "high level" which is subjective. Providing simply an "overview" of the elements is a sufficient description.

3. R1.4.1 - This requirement is very confusing as written. To the point of the use of the terms Operating Plan, Process, and Procedure from our comment #1 above, this requirement needs to be simplified. We suggest rewording to simply: "Criteria for evacuation of the primary control center including the decision authority for initiating the plan or steps required for backup functionality."

4. R1.4.2 - Suggest removing the term "support". The goal of this requirement is to return to full operations, not just operations support.

5. R1.5 - The need to return back to the primary control center is missing from this requirement. Suggest adding the following at the end of this requirement: "as well as the actions to be taken to return back to primary control center functionality."

6. R1.6 - As written, this requirement could be too strict and not allow for personnel flexibility. Suggest rewording the requirement as follows: "Identification of the required roles of involved personnel during the initiation and implementation of the plan or steps required for backup functionality and for the return to the primary control center."

7. R2 - This requirement could be confusing as written and additionally seems to be missing important information regarding the operating and monitoring of the system during the transitional period. Suggest rewording this requirement as follows: "Each Reliability Coordinator, Balancing Authority, Transmission Operator and Generator Operator with a centrally dispatched control center shall have a copy of its plan or steps required for backup functionality located in its primary control center and at the location fulfilling backup functionality, and any facility used for operating or monitoring the BES during the transition process."

8. R3 - We believe that this requirement is duplicative of Requirement R1. The applicability and any delegation of TOP tasks would already be covered by R1. Therefore we suggest removing Requirement R3.

9. R4 - Standards must be followed and adhered to at all times. Therefore the last phrase of this requirement: "… as required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator" is unnecessary and should be removed.

10. R5 - Standards must be followed and adhered to at all times. Therefore the last phrase of this requirement: "… sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively" is unnecessary and should be removed.

11. R9 - To be consistent with other reliability standards, and to allow the entity flexibility in defining roles of authority over Operating Plans, Processes, and Procedures, we suggest removing the last phrase "… by a manager"

12. R9.1 - Since backup functionality includes more elements than just "location, capabilities, and communication protocols", we suggest simplifying this requirement and simply ending the sentence after "… of any changes."

13. R10 - The phrase "any aspect of" should be removed from this requirement. It is not clear what this means and not necessary.

14. R11 - We believe this requirement could be worded better as follows: Each Reliability Coordinator, Balancing Authority, Transmission Operator and Generator Operator with a centrally dispatched control center shall have backup capability to operate for an indefinite period of time."

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	MArk L Bennett	
Organization:	Gainesville Regional Utilities	
Telephone:	352-393-6418	
E-mail:	bennettml@gru.com	

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**	☐	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☒	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: In some cases an entity categorized as a transmission operator may be an entity that has a radial transmission line through their system and there is no nee for either a control center or a back up. They still need a back up plan.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: I do believe that the BU facility, (If one has been established) should be tested annually by the operations personnel once a year. Not necessarily 2 hours a year.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: I believe this needs to be removed. because in the case of a primary facility being lost, everyone in the regiona including NERC and FERC will know the primary facility is lost. Remove requirement. Within 6 months a back up plan has been utilized during the time period.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: R1.4.1 This does not need to be addressed, Any Operational entity in NERC can recognize a reason to abandon their primary Control Center.(Fire, Avalanche, Forest fire, Flood, Tornado, No building, No Computer, GLeaking Gas, etc.) I believe this is not necessary at all R1.4.2 Same reason, when all in normal , we return to the primary facility. R.2 What is the reason to have the Operating plan at both places. Each operator ahs theoretically been trained yearly on the plan and should have an understanding of what is required. What more is needed? The entire SAR needs to addressed. What is required is a plan to continue operation in the case of a primary Control Center, How it is accomplished seems up for more discussion as towhat may be required for continued operation. This SAR as others viseems to view all entities that hav decided to have a back up center rather than a plan meet requirements that are no necessarily needed.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Alessia Dawes	
Organization:	Hydro One Networks	
Telephone:	416-345-5286	
E-mail:	alessia.dawes@hydroone.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: We agree, assuming that for each Generation Station (GS), a GOP normally dispatches using a central control centre and a local control centre is located at the GS.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: The timeframe for the TOP should depend on whether its RC has the capability to be in "operational control" within 2 hours. There is no point in the RC be up and running within the 2 hours frame if they cannot control the system (e.g. switch, breakers). If the TOP is the only entity with "operational control" of Critial Assets or IROLs, then they must also be required to be up and running in the same timeframe as the RC.
   Requirement R8.1. touches on this concept however, we suggest the words are changed to provide for more clarity.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☒ No

Comments: Yes: 2 hours annually is appropriate. However please clarify if this requirement should read, "minimum of two CONTINUOUS hours, annually."

Also, is there consideration in the variance of testing the Operating Plan with respect to weather conditions (e.g. summer conditions vs. winter conditions)? In some locations, weather conditions may have a significant impact on staff transportation time.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: 6 months is too long. We recommend 3-4 months.

As well, please re-word the requirement to provide clairification on whether the plan is needed after the fact (while operating from the back-up facility) or in the planning stages of the Operating Plan? We referring the use of the word "anticipate" in the requirement. The phrases "... anticipate total loss ... will last for more than six months..." and "... within six months of the date when the funcationality is lost.." seem to be in conflict.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☐ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: Requirement R9 states that the Plan must be approved by a manager. Manager of what? This level of approval for such an important plan is too low. We suggest VP or higher. For review, we suggest an applicable "Operating/Control Room Manager".

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Roger Champagne	
Organization:	Hydro-Québec TransÉnergie (HQT)	
Telephone:	514 289-2211, X 2766	
E-mail:	champagne.roger.2@hydro.qc.ca	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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*
Danielle Beaudry	Hydro-Québec TransÉnergie	**NPCC**	1

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: This standard should apply to all RCs, BAs, and TOPs. If an entity is registered as a TOP, their transmission system is part of the BES.
   The intent of providing backup facilities is to ensure the BES continues to be controlled and monitored.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☒ No

   Comments: The applicability of this standard should be restricted to RC, BA, and TOP functions. The GOP's functions is to follow the directions of the BA for demand-energy balance and to ensure that applicable standards are complied to. It is essential that the BA, TOP, and RC have back-up facilities or provisions as specified in this standard but the GOP need not be included as long as the BA ensures that all BA functions are addressed by its back-up facilities.

   However, it is important that GOPs have a backup communication plan in place which must be provided to the appropriate reliability entity upon request.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments:
   R6 needs additional "sub-bullet" to address what happens if the two hour time limit on the RC implementation of the backup plan is exceeded, similar to R8.1.

   It is not the transition time that is in focus here but the system reliability issues which could come up during the transition period which needs to be looked at closely.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: HQT believe that bullets 8.1 and 8.2 are not related to requirement 8, perhaps these should be relocated to requirement 7.

The SDT should clarify why the RC has a maximum delay of 2 hour with no leeway for longer time while the TOP and BA have a maximum delay of 6 hour with a process to have situational awareness if the delay is planned to be greater than 2 hour. HQT believe that the three entities should have the same time delay and leeway time. See our answer to Q3

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: It is a minimum

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: HQT suggest the drafting team to provide for a compliance exemption should the primary or back up control center be lost because of a catastrophic failure.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments:
   Drafting team should clarify the term "GOP centrally dispatched".

   The Drafting Team should focus on the reliability objective as opposed to how the objective is met.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ron Falsetti	
Organization:	IESO	
Telephone:	905-855-6187	
E-mail:	ron.falsetti@ieso.ca	
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**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: This standard should apply to all RCs, BAs, and TOPs as the requirements so stipulate. We are therefore unclear on the basis of this question.

   The intent of providing backup capability/facilities is to ensure the BES continues to be controlled and monitored to balance load-generation-interchange, maintain frequency within acceptable range and loading on transmission network within SOLs and IROLs. BA, TOP and RC are the operating entities that are responsible for these tasks and hence must provide backup facilities to ensure continued control and operation.

   However, if the question is to address the specific provision in the Applicability Section, viz: "Transmission Operator with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits (IROLs).", then our comment would be that the provision should stops at "Critical Assets" since R1.2 in CIP-002-1 clearly stipulates that Critical Assets are those needed to support the reliable operation of the BES, which generally includes monitoring and operating to within IROLs and SOLs. Tying the provision to "with defined IROLs" would allow TOPs that monitors and control SOLs, and deploy/operate BES facilities that could affect BES reliability to be excluded from this standard, which in our view is unacceptable since SOL could become IROL any time as system conditions change.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: We agree that there are other equally effective and efficienct methods for the GOPs to continue to fulfill their obligation to generate, may it be for commercial reasons or reliability reasons.

   Generally speaking, the GOPs follow instructions of the BA, who is responsible for generation-load-interchange balance and maintaining system frequency. We agree that the standard does not need to include GOPs but the reasoning is that the BA will ensure dispatch instruction is provided to the GOPs to meet reliability standards. We recognize that some GOPs elect to set up control centres to operate a group of generators but this is a process set up for business efficiency only. Loss of a GOP operating centre does not hamper the capability of a BA communicating dispatch instructions directly to the generator/generating plant for continuous operation.

However, it is important that GOPs have a backup communications plan in place which must be provided to the appropriate reliability entity upon request.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: The existing requirement R1.8 stipulates that the responsible entity shall have interim provisions if the implementation of the back-up capability plan will take longer than one hour. This draft standard appears to be relaxing this requirement by changing it to two hours. What is the basis for this change?

   We can continue to support the 1 hour requirement. However, if a time frame is to be removed, we recommend that the requirement be written such that the responsible entity shall provide operational capability at all times to ensure continuous operation, monitoring and control of the BES. In this case, it will be up to the responsible entity to demonstrate how its operation and control will continue during the transition period, such as by arranging other entities to take over operation and control during that period.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: We do not understand the rationale behind the difference in the 2-hour time frame for the RC and the 6-hour time frame for the BA/TOP. Mosts RCs rely on the BAs and TOPs to implement actions to ensure reliable operation of its RC area. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant to meet its 2 hour. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC.

   Additionally, we urge the SDT to consider our suggestion made in Q3 that: ".. the requirement be written such that the responsible entity shall provide operational capability at all times to ensure continuous operation, monitoring and control of the BES.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: There should be a mininum amount of testing required. However, we don't see a justification for two hours. We ask the SDT to provide a justification for this important time frame. In the absence of a technical justification, we recommend a full testing of an entity's backup plan be completed regardless of the time required.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: We do not see the need for this requirement. It implies that the responsible entity must establish a long-term or an N-2 contingency plan.

   Losing a primary control capability/facility for a period longer than several days is a rare event, if it has ever occurred before. The need for a long-term plan seems unnecessary. If the backup capability is lost, then the responsible entity would fail its primary requirement of providing the backup capability, unless it immediately re-establish such a capability by securing new facilities or arranging backup by another entity. The need to provide a plan (within 6 months) if the backup capability is lost also seems unnecessary.

   In essence, no time frame needs to be stipulated; just a requirement for the responsible entity to demonstrate the backup capability requirement can continue to be met if the loss of either the primary of backup capability/facility is assessed to be indefinite.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments: Provided that our suggestion in the second part of Q1 is adopted. Letting TOP to decide if this standard applies to them based on their own determination of their critical assets and/or IROLs seems to be a self-regulation process, which violates the legislation establishing a requirement for the ERO.

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments:

   R1 is written with the backup facility in mind. It needs revision if the backup plan is to a backup capability such as by transferring operational control to another operating entity.

R2 - Adresses that the RC, BA and TOP shall have a copy of its operating plan to be physically located at both, the primary control facility and the back-up control facility. It does not address the issue of exchanging this information between the applicable entities. It is essential that the RC is aware of the TOP and BA's operating plans and backup centers - something akin to the system restoration plan - not sure if the RC should review and approve the backup operating plans of the the TOP and BA, but as a minimum, the RC should be provided with the appropriate information by the applicable TOP and BA entities.

R3: It is unclear to us what this requirement aims to accomplish. If a responsible entity has to use other entities to implement its backup functionality, it will be explicitly included in its plan.

R4 should be modified to require each RC to have an arrangement for backup control facility or capability. This requirement will then be more succinct, as stringent, and provide the RC flexibility to make necessary business arrangements to provide backup capability. There is nothing especially important about the RC having its own backup control center or utilizing another RC's control center. It is possible that a third party might be willing to develop control capability to serve as a backup for multiple parties.

R5 is really redundant to R1. If a BA and TOP must have a plan to have backup functionality, they have met Requirement 5.

R9: We do not see the need to specify who in the responsible entity's organization should approve the plan (ref. approved by a manager). This is an internal business process that has nothing to do with reliability. If approval of a backup plan is required, then the responsible entities shall submit their plans to the RE for review and approval.

The version 2 SAR of the subject matter references transmission owners (TOs) with transmission control centers as an applicable entity to this standard. The current draft of the standard is silent on such the appliocability of TOs - was the omission deliberate?If it was, we do not see any statement or logic to this effect.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Kathleen Goodman	
Organization:	ISO New England	
Telephone:	(413) 535-4111	
E-mail:	kgoodman@iso-ne.com	
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**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: This standard should apply to all RCs, BAs, and TOPs. If an entity is registered as a TOP, their transmission system is part of the BES. This is equivalent to letting a given TOP decide if a standard applies to them. Clearly, if they do not operate BES equipment, they should not be registered at all.

   The intent of providing backup capabilities is to ensure the BES continues to be controlled and monitored to balance load-generation-interchange, maintain frequency within acceptable range and loading on transmission network within SOLs and IROLs. All TOPs are the operating entities that are responsible for some of these tasks and hence must provide backup capabilities to ensure continued control and operation.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☒ No

   Comments: The applicability of this standard should be restricted to RC, BA, and TOP functions. The GOP's functions is to follow the directions of the BA for demand-energy balance, follow diections from the TOP with respect to voltage control, and to ensure that applicable standards are complied to. It is essential that the BA, TOP, and RC have back-up facilities or provisions as specified in this standard but the GOP need not be included as long as the BA ensures that all BA functions are addressed by its back-up plans.

   However, it is important that GOPs have backup communications in place for failure of their primary communications path. But, this would likely be in a COM Standard.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments:

R6 needs additional "sub-bullet" to address what happens if the two hour time limit on the RC implementation of the backup plan is exceeded, similar to R8.1.

It is not the transition time that is in focus here but the system reliability issues which could come up during the transition period which needs to be looked at closely.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Bullets 8.1 and 8.2 appear to be related to requirement 7, not 8.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: It is a minimum

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: This requirement is trying to anticipate every conceivable situation that could occur. Standards should not be written to anticipate all possible situations. In reality, this is a business continuity issue and does not belong in the standard. Most professionals with business continuity responsibilities believe that the risk of losing your main control center for such an extended period is extremely low. Most likely an entity will only have to implement their back-up capability plan for a short period of time and will be able to re-occupy their main control center. Additionally, there are simply too many variables involved in establishing new backup capability for an extended period of time. The ERO and REs should work closely with the affected entity to develop a plan to restore backup capability to address this unlikely situation.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments:
   The Drafting Team should focus on the reliability objective as opposed to how the objective is met.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
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: ISO RTO Council/Standards Review Committee (SRC)

Lead Contact: Charles Yeung

Contact Organization: Southwest Power Pool

Contact Segment: 2

Contact Telephone: 832-724-6142

Contact E-mail: cyeung@spp.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Patrick Brown	PJM	RFC/SERC	2
Jim Castle	NYISO	NPCC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Anita Lee	AESO	WECC	2
Steve Myers	ERCOT	ERCOT	2
Bill Phillips	Midwest ISO	RFC/SERC/MRO/SPP	2

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: This standard should apply to all RCs, BAs, and TOPs. If an entity is registered as a TOP, their transmission system is part of the BES. Any part of the BES could become limited by an IROL under certain conditions. Furthermore, TOPs are responsible for identifying their own Critical Assets and IROLs. Thus, this is equivalent to letting a given TOP decide if a standard applies to them. Letting a responsible entity determine if a standard applies to them is a form of self-regulation.

   The intent of providing backup capabilities is to ensure the BES continues to be controlled and monitored to balance load-generation-interchange, maintain frequency within acceptable range and loading on transmission network within SOLs and IROLs. All TOPs are the operating entities that are responsible for some of these tasks and hence must provide backup capabilities to ensure continued control and operation.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: The regulatory approved reliability standard currently requires that a responsible entity have interim provisions if the implementation of the back-up capability plan will take longer than one hour. This draft standard appears to be reducing the stringency of this requirement by changing it to two hours. What is the justification for this? Are there responsible entities experiencing difficulties meeting the requirement? If all responsible entities are currently compliant with the requirement, why increase the time frame?

In fact, we recommend that time frame should not be considered. The entity should be responsible for meeting a core set of requirements at all times.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Mosts RCs only have functional control of the transmission system. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC.

In fact, we recommend an alternative approach to a time limit in question 3. We repeat that here and suggest it for application to the TOP and BA as well.

In fact, we recommend that time frame should not be considered. The entity should be responsible for meeting a core set of requirements at all times.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: There should be a mininum amount of testing required. However, we don't see a justification for two hours. Why not one or three? The SDT should establish a justification for this important time frame. It should not be arbitrary or based on judgment. A full test of an entity's test plan should be completed regardless of the time required.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: This requirement is trying to anticipate every conceivable situation that could occur. Standards should not be written to anticipate all possible situations. In reality, this is a business continuity issue and does not belong in the standard. Most professionals with business continuity responsibilities believe that the risk of losing your main control center for such an extended period is extremely low. Most likely an entity will only have to implement their back-up capability plan for a short period of time and will be able to re-occupy their main control center. Additionally, there are simply too many variables involved in establishing new backup capability for an extended period of time. The ERO and REs should work closely with the affected entity to develop a plan to restore backup capability to address this unlikely situation.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☒ Yes

   ☐ No

   Comments: Allowing a BA or TOP to in effect determine if the standard applies to them because they determine their critical assets and/or IROLs is equivalent to self-regulation which is clearly a violation of the legislation establishing a requirement for the ERO.

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: In general, this requirement is overly detailed and broad. There are really only three basic requirements for establishing backup operational capability. Those three requirements are:

   1. Have a plan
   2. Test plan

3. Implement when needed.

Any requirements beyond these three basic requirements will only detract from reliability because they will cause entities to focus on requirements outside of these basics.

Many of the subrequirements in this standard are not requirements at all. Rather they are criteria or lead-in statements for other subrequirements. This is problematic because the FERC has established VRFs for subrequirements in the past that are really not requirements and is now requiring the establishment of VSLs for many subrequirements that are not requirements at all or may even be explanatory text. This draft standard is perpetuating this problem.

Any subrequirements that are criteria should simply be listed as bullets under the requirement with the requirement specifying that it is subject to the following criteria. For instance, all subrequirements under R1 do not really have any requirement. They are simply a list of what should be included in the plan identified in R1 or explanatory text. Thus, many of these sub-requirements should simply become bullets. This would also aid in the establishment of multiple VSLs because an entity that has a plan but is only missing couple of the requirements might have a low VSL. Whereas an entity, not having a plan would then fall into the SEVERE VSL.

R1.1 is not necessary but is simply a part of a plan. A plan doesn't exist if it doesn't identify where and how. This could be specified as a criterion for the plan.

R1.2 is unneccesary. First, high level is subjective. Requirements should not be subjective. Secondly, each of the sub-requirements under it will stand alone without R1.2.

R1.3 should be modified. What it really needs to state is that the backup functionality needs to have current BES data. It should not be tied to what the primary control center has because the primay control center data may be out of synch with the BES. This would be a reason to utilize the backup functionality.

R1.4 is not necessary. The subrequirements under it do an adequate job of spelling out the basic minumum requirements without the introductory statement that R1.4 is. A third criteria should be added that identifies who makes the decision to implement the back-up plan.

R2 is not necessary if there is going to be timing requirements for bringing the backup functionality. It is a good idea but should not be a requirement. In effect, requiring the backup functionality to be functioning in x amount of time will cause the responsible entity to have the plan at their fingertips. Additionally, a properly trained system operator should be able to implement the plan without referring to the plan.

R3 is a requirement that is an example of an attempt to write the standard for a every conceivable sitiuation and is not necessary. If a responsible entity has to use other entities to implement its backup functionality, it will be explicitly included or they will not have a plan that they can test. Thus, they will not meet requirement.

R4 should be modified to require each RC to have arranged for the availability of back-up capability. This requirement will then be more succinct, as stringent, and provide the RC flexibility to make necessary business arrangements to provide back-up capability. There is nothing especially important about the RC owning its own backup control center or utilizing another RC's control center. It is possible that a third party that is not an RC might be willing to develop a control center to serve as a backup for multiple parties. As long as the requirement functionality is provided, why would this be a problem? The requirement as written would preclude this satisfactory arrangement.

R5 is really redundant to R1. If a BA and TOP must have a plan to have backup functionality, they have met Requirement 5. Let's not create an opportunity for double jeopardy.

Requirement 8 and all of its subrequirements are not really requirements. It really is criteria for R1.

Requirement 9 should remove the requirement to have the plan approved by a manager. This is really a business process requirement and does nothing to ensure reliability. Besides, Requirement 13 will cause this to happen anyway. Do you really think that the plan can be tested annually without a manager's approval?

R10 and R11 is not really a requirement. It belongs as a criterion under R1.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Joseph DePoorter	
Organization:	Madison Gas and Electric Company	
Telephone:	608-252-1581	
E-mail:	jdepoorter@mge.com	
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**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☒	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: This standard should apply to all RCs, BAs, and TOPs. Any loss of primary control center may have a hugh effect on the BES. All TOPs should be required and if they believe they should not be, then the TOP should request a waiver from NERCie, if the TOP only had a small radio fed transmission system.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: A "less than two hour" window to fully implement the backup plan and get backup functionality up and running is and can be a great task. There should be a provision that if ther backup plan can not be obtained within the two hour time frame.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: Since R8.1 and R8.2 break down R7, they should be renumbered as sub bullets to R7.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: There should be adequate testing of the backup facility. A two hour annual test could consist of four, 30 minute periods. R12 should be written that "... implementation or test operations to ensure the RC, TOP, BA's minimum requirements are met per R1". This would ensure that the Operating Plan was implemented and all sub bullets of R1 are tested or simulated. As a BA, we would want to see an entire hour (hour ending X to hour ending Y) of information. This would allow us to ensure that the Operating Plan of R1 is satisified.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: We do not "anticipate" the loss of our primary or backup capability. If a RC, TOP , or BA was without their primary control center for any length of time it would have an impact on their revenue generation and would place a burden on "whoever" was assisting them. I would think that the Regional Entity would be involved and the RC, TOP or BA would be working to get their primary control center up and running as soon as possible. FERC Order 693 does not state a 6 month time frame. R13 could state that the Regional Entity will be notified whenever the primary control center is non-functional except when the backup control center is being tested or training is taking place. The RE will have a plan fullfilling R1 requirements if the primary and backup facilities are non operatible.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☒ Yes

   ☐ No

   Comments: R8.2 states that the Operating Procedure will ensure the calculation and control of ACE beyond the two hour time period. BAL-005-0, R6 states that if a BA is unable to calculate ACE for more than 30 minutes it shall notify its RC. Perhaps the wording of R8.2 should be the same as BAL-005-0, R6 so there is no confusion.

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: R5 should be broken down into sub bullets, ie: R5.1, monitoring, R5.2, Control, R5.3, Logging, ect.

R9 The last three words should be deleted "by a manager". Some entities may not have "manager" in the title of the position that writes and implements the Operating Plan.

R10, the last sentence uses the words "any aspect" and needs to be removed. FERC Order 693, para 663 states "... and the provision of a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center". The statement "any aspect" implies we can use nothing from the primary control center. What if I rely on security cameras to ensure Cyber security of both sites when dealing with physical security perimeters? Even though I may not be using the primary site for control I still have to protect it. I suggest new wording of "... does not depend on the primary control center for its functional operations". Or words to that effect.

It is helpful to the Utility Industry if Measurements, Compliance, Data Retention, VSL's, ect are in the draft standard. This allows us to see the whole picture of what is being proposed. It may even speen up the SAR process.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Doug Rempel	
Organization:	Manitoba Hydro	
Telephone:	204 487 5427	
E-mail:	dbrempel@hydro.mb.ca	

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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: The TOP is as responsible as any entity in operating the BES, therefore their facilities are as important to the reliable operation of the BES as an RC or BA. I fail to see how the applicability is limited by the statement in the applicability section 4.1.2, any TOP with an EMS/SCADA system has critical assets and needs to protect against the loss of those assets.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: The GOP still needs to have a plan to continue its operations should they loose control centre functionality. The GOP may not be required to meet every requirement in the standard but they should have a plan to continue operations as per Requirement 1.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: The time frame is too long, a lot can happen in six hours including mother nature dropping a lightning storm on top of the entity, which can cause much greater problems to the entity than the limited control they have during a transition period. I would suggest a time period of two hours.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: I think the time frame should be left up to the entity, they just have to ensure the backup is tested thoroughly.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: I agree with MISO's comments in that this belongs in business continuity planning and should not be in the standard.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☐ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: Requirement R1.1 is too loose and is open to interpretation.
   Does R1.6 include the roles of support personnel including field personnel that may be required to staff stations during the transfer?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td>Name:</td><td colspan="2">Donald E. Nelson</td></tr>
<tr><td>Organization:</td><td colspan="2">Massachusetts Department of Public Utilities</td></tr>
<tr><td>Telephone:</td><td colspan="2">617-305-3657</td></tr>
<tr><td>E-mail:</td><td colspan="2">Donald.E.Nelson@state.ma.us</td></tr>
<tr><td>NERC Region (check all Regions in which your company operates)</td><td></td><td>Registered Ballot Body Segment (check all industry segments in which your company is registered)</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☐ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
<tr><td>☐</td><td>2 — RTOs and ISOs</td></tr>
<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
<tr><td>☐</td><td>4 — Transmission-dependent Utilities</td></tr>
<tr><td>☐</td><td>5 — Electric Generators</td></tr>
<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☒</td><td>9 — Federal, State, Provincial Regulatory or other Government Entities</td></tr>
<tr><td>☐</td><td>10 — Regional Reliability Organizations and Regional Entities</td></tr>
</table>

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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments: R1.8 of the existing standard - while not placing an absolute deadline - envisions that the backup for the primary control facility of the reliability coordinator will be operational within one hour. There is no explanation as to why one hour is no longer a credible target timeframe for backup facility operation and needs to be doubled to two hours.

   A more rationale approach is to institute a plan that is expected to have the backup control facility functional within one hour, but if there are unforeseen circumstances that prevent operation within one hour, then there will not be a penalty associated with the second hour. An example would be that if the circumstances that disabled the primary control facilities made access to the backup difficult (e.g. flood that took out both the control center and surrounding roads) and it physically took longer than expected to reach the backup center, then there would be no penalty until two hours elapsed. However, if the event was a computer glitch and there were no significant obstacles to reaching the backup facilities, the one hour limit would control.

   If this proposal is unworkable from a standards drafting perspective, the standard should only allow a one hour transition time consistent with the existing standard instead of a two hour limit as proposed. The longer the system is outside of a standard operating mode there is a higher risk of serious reliability problems, which should not be allowed at the reliability coordinator level.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments: Regardless of the timeframe between a primary control center going down and activation of the backup facility, having a plan in place to seamlessly operate the system is paramount. As stated in question 3, one hour should be used for the reliability coordinator instead of two hours.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☐ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: **Midwest ISO Standards Stakeholder Collaborators**

Lead Contact: Jason L. Marshall

Contact Organization: Midwest ISO

Contact Segment: **2**

Contact Telephone: 317-249-5494

Contact E-mail: jmarshall@midwestiso.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Cyrulewski, P.E.	JDRJC Associates	RFC	8
Barb Kedrowski	We Energies	RFC	3,4
Jeanne Kurzynowski	Consumers Energy Company	RFC	3,4,5

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: This standard should apply to all RCs, BAs, and TOPs. If an entity is registered as an TOP, their transmission system is part of the BES. Any part of the BES could become limited by an IROL under certain conditions. Furthermore, these entities are responsible for identifying their own Critical Assets and IROLs. Thus, this is equivalent to letting a given TOP decide if a standard applies to them. Letting a responsible entity determine if a standard applies to them is a form of self-regulation.

   This is really a registration issue that should be determined by the Regional Entities. If the RE determines an entity meets the TOP registration criteria, then that entity should be subject to the same standards as any other TOP.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: Standards are not supposed to define the "how" but rather they are supposed to define the "what". The SDT is focused on the "how". Within this very question, the SDT acknowledges that there are other equally effective and efficienct methods for the GOPs to continue to fulfill their role in preserving reliability. We agree that is true, however, the SDT needs to define that role in preserving reliability. For instance, does the GOP need to have a plan to continue to dispatch the units in the event their central dispatch office fails? That plan could involve a number of solutions but the role is a focused on "what" needs to be accomplished.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: Why did the standards drafting team increase the transition time frame from the one hour requirement in the existing standards? The drafting team needs to provide strong justification for this. If all RCs are currently meeting the standard one hour transition time frame in the existing standards, it is hard to fathom any reason to increase it.

Rather than specify a time frame for transition, we suggest alternative approach that is more justifiable. This approach would require the responsible entity to have minimal capability to meet the core set of applicable requirements during the transition. The drafting team will need to identify those core set of requirements.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Mosts RCs only have functional control of the transmission system. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC unless our alternative approach in our response to question three is adopted.

Our alternative approach presented in our comments in question three should apply here as well. It is included below.

Rather than specify a time frame for transition, we suggest alternative approach that is more justifiable. This approach would require the responsible entity to have minimal capability to meet the core set of applicable requirements during the transition. The drafting team will need to identify those core set of requirements.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: There should be a mininum amount of testing required. However, we don't see a justification for two hours. Why not one or three? The SDT should establish a justification for this important time frame. It should not be arbitrary or based on judgment.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: This requirement is trying to anticipate every conceivable situation that could occur. Standards should not be written to anticipate all possible situations. In reality, this is a buisness continuity issue and does not belong in the standard. Most professionals with business continuity responsibilities will tell you that the risk of losing your main control center for such an extended period is extremely low. Most likely an entity will only have to operate out of their backup control center for a short period of time and will be able to re-occupy their main control center. Additionally, there are simply too many variables involved in establishing new backup capability for an extended period of time. The ERO and REs will simply have to work closely with the affected entity to develop a plan to restore backup capability given this unprobable situation.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☒ Yes

☐ No

Comments: Allowing a BA or TOP to in effect determine if the standard applies to them because they determine their critical assets and/or IROLs is equivalent to self-regulation which is clearly a violation of the legislation establishing a requirement for the ERO.

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: In general, this requirement is overly detailed and broad. There are really only three basic requirements for establishing backup operational capability. Those three requirements are:

1. Have a plan
2. Test plan
3. Implement when needed.

Any requirements beyond these three basic requirements will only detract from reliability because they will cause entities to focus on requirements outside of these basics.

Many of the subrequirements in this standard are not requirements at all. Rather they are criteria or lead-in statements for other subrequirements. This is problematic because the FERC has established VRFs for subrequirements in the past that are really not requirements and is now requiring the establishment of VSLs for many subrequirements that are not requirements at all or may even be explanatory text. This draft standard is perpetuating this problem.

Any subrequirements that are criteria should simply be listed as bullets under the requirement with the requiirment specifying that it is subject to the following criteria. For instance, all subrequirements under R1 do not really have any requirement. They are simply a list of what should be included in the plan identified in R1 or explanatory text. Thus, many of these sub-requirements should simply become bullets. This would also aid in the establishment of multiple VSLs because an entity that has a plan but is only missing couple of the requirements might have a low VSL. Whereas an entity, not having a plan would then fall into the SEVERE VSL.

R1.1 is not necessary but is simply a part of a plan. A plan doesn't exist if it doesn't identify where and how. This could be specified as a criterion for the plan.

R1.2 is unneccesary. First, high level is subjective. Requirements should not be subjective. Secondly, each of the sub-requirements under it will stand alone without R1.2.

R1.3 should be modified. What it really needs to state is that the backup functionality needs to have current BES data. It should not be tied to what the primary control center has because the primay control center data may be out of synch with the BES. This would be a reason to utilize the backup functionality.

R1.4 is not necessary. The subrequirements under it do an adequate job of spelling out the basic minumum requirements without the introductory statement that R1.4 is. A third criteria should be added that identifies who makes the decision.

R2 is not necessary if there is going to be timing requirements for bringing the backup functionality. It is a good idea but should not be a requirement. In effect, requiring the backup functionality to be functioning in x amount of time will cause the responsible entity to have the plan at their fingertips. Additionally, a properly trained system operator should be able to implement the plan without referring to the plan.

R3 is a requirement that is an example of an attempt to write the standard for a every conceivable sitiuation and is not necessary. If a responsible entity has to use other entities to implement its backup functionality, it will be explicitly included or they will not have a plan that they can test. Thus, they will not meet requirement.

R4 should be modified to require each RC to have arranged for the availability of a backup control center. This requirement will then be more succinct, as stringent, and provide the RC flexibility to make necessary business arrangements to provide a backup center. There is nothing especially important about the RC owning its own backup control center or utilizing another RC's control center. It is possible that a third party that is not an RC might be willing to develop a control center to serve as a backup for multiple parties. As long as the requirement functionality is provided, why would this be a problem? The requirement as written would preclude this satisfactory arrangement.

R5 is really redundant to R1. If a BA and TOP must have a plan to have backup functionality, they have met Requirement 5. Let's not create an opportunity for double jeopardy.

Requirement 8 and all of its subrequirements are not really requirements. It really is criteria for R1.

Requirement 9 should remove the requirement to have the plan approved by a manager. This is really a business process requirement and does nothing to ensure reliability. Besides, Requirement 13 will cause this to happen anyway. Do you really think that the plan can be tested annually without a manager's approval?

R10 and R11 is not really a requirement. It belongs as a criterion under R1.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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: MRO NSRSi

Lead Contact: Michael Brytowski

Contact Organization: MRO

Contact Segment: 10

Contact Telephone: 651-855-1728

Contact E-mail: mj.brytowski@midwestreliability.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	WPS	MRO	3,4,5,6
Terry Bilke	MISO	MRO	2
Robert Coish	MHEB	MRO	1,3,5,6
Carol Gerou	MP	MRO	1,3,5,6
Jim Haigh	WAPA	MRO	1,6
Ken Goldsmith	ALTW	MRO	4
Tom Mielnik	MEC	MRO	1,3,5,6
Pam Oreschnick	XCEL	MRO	1,3,5,6
Dave Rudolph	BEPC	MRO	1,3,5,6
Eric Ruskamp	LES	MRO	1,3,5,6
Joseph Knight	GRE	MRO	1,3,5,6
Michael Brytowski	MRO	MRO	10
Larry Brusseau	MRO	MRO	10
Joseph DePoorter	MGE	MRO	3,4,5,6
Wayne Guttormson	SaskPower	MRO	1,3

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: No, according to the NERC glossary of terms the transmission operator is that "... entity (which is responsible) for reliability of its "local" transmission system, and that operates or directs the operation of the transmission facilities." Taking this into account, this standard speaks to the lost of these transmission facilities and how the transmission operator plans to handle these lost facilities. All transmission operators which operate Bulk Electric System should be applicable to this standard since bulk electric facilities, systems, and equipment which if destroyed, degraded, or otherwise rendered unavailable would affect the reliability or operability of the BES since the BES would no longer be capable of functioning. (Also, please note I am not referring to the lost of one transmission line or a generator but a loss of an entire "local" transmission system operated by a transmission operator.) Is it possible for a transmission operator to operate a transmission facility which is not included in the BES? If so, then perhaps this standard should not apply to them. Please give an example of a transmission operator who does not operate BES facilities?

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: The SDT should include the Generator Operator within this standard especially if GOP can efficiently and effectively fulfill their role in preserving the reliability of the interconnection following the loss of the GOP's control center.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: Not sure, where did the 2-hour transition time frame come from? Is it reasonable to assume that 2 hours may not be possible? For example, what if a snow/ice storm of the century hits the control area in question? The ice storm renders the primary control center inoperable. Mobility to the backup control center is arrested due to massive snow fall. Is a Reliability Coordinator still reasonably expected to have the backup control center operational within 2 hours after the loss of the primary control center? The weather I describe is probable and it's planned for in designing facilities shouldn't we at least consider this situation as a possibility? To account for this possibility perhaps this time frame and the other time frames listed in this standard should be modified to allow the Compliance Monitor the option to arrest this requirement during natural destroyers or not prescribe a specific time period but say to operators you must make every foreseeable effort to transition as soon as possible.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☒ No

Comments: The MRO would like to question why in this era of "hot" standby systems would it take an RC 6 hours to get their backup site operating? The MRO would like the SDT to share the methodology they used in determining these time periods.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: That depends on the conditions during the test. Operators may not be aware of specific issues with the back up control center if they only operate that location for two hour annually, plus, issues may emerge outside the 2 hour testing operational period;It's difficult to say what those issues may be at this time.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: Appropriateness depends on what is needed to show the re-establishment of backup capability. What if an action is contingenct upon restriants that may take awhile to process like a building permit or limiting weather conditions restricting the re-establishment process(es)?

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments: N/A

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: During the transitional period were neither the primary or the backup control center are fully functionable, should the system operator have a copy of the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location? For example, lets say the primary control center is not functionable. The system operators become mobilized to make their way to the backup control center. They have everything they need, laptops, sattellite phones, etc but they don't have a copy of the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location until, they get to the back up control center. What if they are not able to get to the backup control center, but could wirelessly access the backup control center capabilities, thus allowing them to perform but in a limited fashion since they don't have the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location? Thus, the SDT should address the transitional period in a more developed fashion perhaps allowing the system operators to operate from another location other than the backup control center if need be found and the system operators have that capability.

R9. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall have its Operating Plan for backup functionality reviewed and approved annually by a manager.

The reference to the manager should be removed. NERC should only be concerned with having the RC, BA, and TOP annually review its plan. Requiring approval of anything internal is outside the scope of a NERC reliability standard, though they have used this concept in other standards.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Tony Eddleman
Organization:	Nebraska Public Power District
Telephone:	402-845-5253
E-mail:	tdeddle@nppd.com

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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: The 2-hour transition time is too restrictive - recommend a minimum of six hours.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: This standard addresses an event that probably will never happen for the vast majority of TO's and BA's. Shorter time frames require more elaborate and expensive systems (i.e. hot back-up versus cold back-up). The additional complexity isn't justified by the probability of having an event. Instead of two hours, the time to transition functions to the backup should be six hours. The backup should be fully functional within 24 hours after the event. An actual event, noted to be extremely rare to occur, will probably result in the loss of human life and infrastructure. The initial discovery and realization to implement the backup will be delayed by emergency response and the real-world crisis. Shorter response times could require 7 X 24 staffing at the Backup Facility. I'm not aware of a significant number of actual events that had demonstrated this need.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments: As long as it's a plan for re-establishing backup capability and not the actual backup capablity restored in six months, this requirement is achievable.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments:
Paragraph A.5. - Recommend a minimum of 36 months to implement the requirements in the standard after the effective date before the standard is auditable.

Paragraph B.R9. - Delete, "by a manager". Each entitity should decide who has review and approval authority for its Operating Plan.

Paragraph B.R9.1. - Requiring the Operating Plan to be updated and re-approved within sixty calendar days of any change is too restrictive. Major changes would require an update to the plan, but most changes could wait for the annual review.

Paragraph B.R11. - Requiring a Backup Facility to be capable of operating for an indefinite period of time increases the complexity and adds unnecessary costs to the facility. Is this requirement mandating training facilities at the backup, including simulators, plus all the support staff for a Control Center. These functions are best addressed through an interium plan developed after the event occurs; then, permanent facilities implemented with a plan to restore the primary. The actual situation that occurs will dictate how much and to what extent these are needed.

General Comment: Our utility has spent a considerable amount on our primary facility to harden the facility and provide redundancy. Requiring us to invest in a fully operative backup facility redirects funding from needed infrastructure improvements in other areas. The actual probability and risk of needing a backup facility are very minimal, compared to transmission infrastructure improvements that clearly will provide value through increased ratings and reliability. Recommend the existing NERC requirements to have a plan to continue operations in the event its control center becomes inoperable be retained and the new requirements for a fully functional backup facility be eliminated. If this recommendation is not implemented, please provide justification from actual situations why these requirements are required.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Diane Barney	
Organization:	New York State Dept of Public Service	
Telephone:	518-486-2943	
E-mail:	diane_barney@dps.state.ny.us	
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**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☒	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: R1.8 of the existing standard - while not placing an absolute deadline - envisions that the backup for the primary control facility of the reliability coordinator will be operational within one hour. There is no explanation as to why one hour is no longer a credible target timeframe for backup facility operation and needs to be double to two hours.

   A more rationale approach is to institute a plan that is expected to have the backup control facility functional within one hour, but if there are unforeseen circumstances that prevent operation within one hour, then there will not be a penalty associated with the second hour. An example would be that if the circumstances that disabled the primary control facilities made access to the backup difficult (e.g. flood that took out both the control center and surrounding roads) and it physically took longer than expected to reach the backup center, then there would be no penalty until two hours elapsed. However, if the event was a computer glitch and there were no significant obstacles to reaching the backup facilities, the one hour limit would control.

   If this proposal is unworkable from a standards drafting perspective, the standard should only allow a one hour transition time consistent with the existing standard instead of a two hour limit as proposed. The longer the system is outside of a standard operating mode there is a higher risk of serious reliability problems, which should not be allowed at the reliability coordinator level.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Regardless of the timeframe between a primary control center going down and activation of the backup facility, having a plan in place to seamlessly operate the system is paramount. As stated in question 3, one hour should be used for the reliability coordinator instead of two hours.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☐ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☐ No

   Comments:

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Rick White		
Organization: Northeast Utilities		
Telephone: 860-665-2572		
E-mail: whitefb@nu.com		
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: An individual generator should not impact the reliability of the BPS.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: 2 hours maximum seems more appropriate.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: Yes, as a minimum.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: 6 months seems excessive. It seems within 2 months an entity should at least have a plan.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: R9.1 "...within sixty calendar days of any changes to the backup location, capabilities, or communication protocols." is wide open. It seems there could be changes made that improve capabilities or communication protocols that would not meet the threshold of a revision to the plan, such as a tool added to the primary center that works similarly at the Backup Center. The words "any changes" are too broad, possibly replace with "significant changes that impact the Operating Plan….." or similar.

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: NPCC Regional Standards Committee

Lead Contact: Mr. Guy Zito

Contact Organization: NPCC

Contact Segment: Regional Standards

Contact Telephone: 212-840-1070

Contact E-mail: **Gzito@npcc.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Guy Zito	NPCC	NPCC	10
Lee Pedowicz	NPCC	NPCC	10
Brian Evans-Mongeon	Utility Services, LLC	NPCC	6
Randy MacDonald	New Brunswick System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1, 2
Ronald Hart	Dominion Resources, Inc.	NPCC	5
Biju Gopi	Independent Electricity System Operator	NPCC	2
Murale Gopinathan	Northeast Utilities	NPCC	1, 4
Michael Ranalli	National Grid	NPCC	1, 4
Kathleen Goodman	ISO New England	NPCC	2
Ralph Rufrano	New York Power Authority	NPCC	1, 4, 5, 6, 9
Peter Yost	Consolidated Edison Company of New York, Inc.	NPCC	1, 4, 5, 6
Roger Champagne	Hydro-Quebec TransEnergie	NPCC	1, 2
Gregory Campoli	New York Independent System Operator	NPCC	2
Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
Donald Nelson	Massachusetts Department of Public Utilities	NPCC	9
David Kiguel	Hydro One Networks	NPCC	1, 3

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☒ No

   Comments: The applicability of this standard should be restricted to RC, BA, and TOP functions. The GOP's functions is to follow the directions of the BA for demand-energy balance and to ensure that applicable standards are complied to. It is essential that the BA, TOP, and RC have back-up facilities or provisions as specified in this standard but the GOP need not be included as long as the BA ensures that all BA functions are addressed by its back-up facilities.

   However, it is important that GOPs have a backup communication plan in place which must be provided to the appropriate reliability entity upon request.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments:
   R6 needs additional "sub-bullet" to address what happens if the two hour time limit on the RC implementation of the backup plan is exceeded, similar to R8.1.

   It is not the transition time that is in focus here but the system reliability issues which could come up during the transition period which needs to be looked at closely.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: NPCC participating members believe that bullets 8.1 and 8.2 are not related to requirement 8, perhaps these should be relocated to requirement 7.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: It is a minimum

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: NPCC participating members suggest the drafting team provide for a compliance exemption should the primary or back up control center be lost because of a catastrophic failure.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments:
   Drafting team should clarify the term "GOP centrally dispatched".

   The Drafting Team should focus on the reliability objective as opposed to how the objective is met.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words “BF Standards” in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Stan Southers / Ellis Rankin	
Organization:	Oncor Electric Delivery Company LLC	
Telephone:	214-486-2084 / 214-743-6825	
E-mail:	stan.southers@oncor.com / erankin@oncor.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☐ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: Requirement R3 is a step in the right direction. The intent is to be sure that local control centers that provide significant BES operating activities but which are not TOPs themselves also have backup capability. The requirement as written is subject to significant interpretation and it isn't clear whether the requirement achieves the desired outcome. For example, one interpretation would be that the TOP backup plan has to consider being able to operate with the local control center through its backup plan, but a more robust interpretation would address whether the backup facility plan of the TOP has also taken care of the loss of the primary control center for the local control center. This issue would typically arise when a Transmission Owner operates a primary control center that is important to BES reliability, but which is not themselves a Transmission Operator. The direct method would be to make these Transmission Owners a responsible entity. However, if the intent is to get to this concern through the Transmission Operator, then additional clarity in R3 is necessary.

   A very important issue that must be dealt with in this standard is the issue of enforcement of this standard following loss of the primary control center. There are two distinct dimensions to this issue. One is that during the transition period from the primary facility to the backup capability it needs to be recognized that not all reliability functions will be able to be accomplished. Specific waiver from compliance is very important during this transition period. Unless such a waiver is provided, the standard will essentially require that zero transition time is allowed between loss of primary control center and full functionality of backup capability. Such a requirement would essentially require a fully staffed hot backup capability at all times. Oncor believes such a requirement will be too expensive and not warranted. A second dimension to this compliance concern follows the loss of the primary control center itself. After the backup capability is fully functioning, compliance with all reliability standards would be expected, but the concern is whether compliance with EOP-008 itself would still be required. Unless it is clear that the provision of a backup capability is not required during the period that the primary capability has been lost, the result will be that a backup to the backup capability must be provided at all times. Oncor strongly believes that there is no credible reliability argument that would indicate that such a 3 deep backup capability is warranted, and without such a waiver the standard would impose unreasonable costs on the industry.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Robert Williams	
Organization:	PacifiCorp Grid Operations	
Telephone:	(503) 251-5197	
E-mail:	robert_l.williams@pacificorp.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: If the site for the backup facility must be completely reconstructed, it may not be feasible for it to be re-established within 6 calendar months. 6 months to a year would be more appropriate, allowing room to relocate and re-establish, if necessary.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☐ Yes

☒ No

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Lauri Jones
Organization:	Pacific Gas and Electric Company
Telephone:	415-973-0918
E-mail:	llj8@pge.com

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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: It is our understanding that the drafting teams are given specific direction in following the FERC Order 693 directive. If this approach had been followed then the team would respond to industry comments during the comment review period. This approach will further delay the standard implementation period.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

   Comments: It is also unclear as to who will be testing it? Are the Operating Plans for the functionality to be tested for the two hours annually, ment for each operator or is it only for that control center, once per year?

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: PJM Interconnection

Lead Contact: Patrick Brown

Contact Organization: PJM Interconnection

Contact Segment: 2

Contact Telephone: 610-666-4597

Contact E-mail: **brownp@pjm.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Joe Willson	PJM Interconnection	RFC/SERC	2
Mike Bryson	PJM Interconnection	RFC/SERC	2
Al DiCaprio	PJM Interconnection	RFC/SERC	2

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "BF Standards" by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: According to NERC's Statement of Compliance Registry Criteria (Revision 4.0), any entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities, and is directly connected to the bulk power system (>100 kv), is required to register as a TOP. As such, the loss of any TOP's primary control facilities could have a major impact on wider system reliability. Therefore, ALL registered TOPs should be included in this standard.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: Although GOPs should not be required to maintain backup facilities, they should be required to have a backup communications plan under the COM standards.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: The current, approved version of EOP-008, R1.8, states "Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility." We believe this time-frame is appropriate and in the best interest of system reliability, and therefore should not be relaxed.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

Comments: RC's typically have a limited ability to control generation or transmission facilities. Without the BA and TOP control facilities, the RC will not be able to effectively perform its' functions. Therefore, the BA and TOP entities should be required to meet the same one hour time limit that applies to RCs.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: The two hour requirement appears to be arbitrary and should not be included in the standard. The standard should state something to the effect that “Each Reliability Coordinator, Balancing Authority and Transmission Operator shall test its Operating Plan for backup functionality through actual implementation or test operations on a semi-annual basis.”

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: The structure of the requirement is confusing. We suggest that it be re-written as "If the Primary or backup functionality is lost then each RC, TOP and BA shall provide a plan to its Regional Entity within six calendar months showing how it will re-establish backup capability"

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven’t already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: We suggest requirement 8 be rewritten to read;

"For each RC, TOP and BA, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations."

R8.1 and R8.2 can be eliminated since the time requirements suggested above are the same for BA, TOP, RC.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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:	Public Service Commission of South Carolina
Lead Contact:	Phil Riley
Contact Organization:	Public Service Commission of South Carolina
Contact Segment:	9
Contact Telephone:	803-896-5154
Contact E-mail:	philip.riley@psc.sc.gov

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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☒ No

   Comments:

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Mark Willis	
Organization:	SMUD	
Telephone:	(916) 732-5451	
E-mail:	mwillis@smud.org	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: All BES entities registered as TOPs should have the same requirements.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: The Centrally controlled GOPs have to have a plan to operate if they lose their central control center. The impact to the BES could be the same as for a TOP.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: In the role of the RC, a 2-hour period is insufficient for required reliability covereage, and should be 1-hour.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: In the role of a BA or TOP, a 2 to 6-hour time frame is insufficient for required reliable operation of the BES, and should be no greater than 2-hours.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: To ensure familiarity with an entity's BCC, a mimimum of two weeks (14 days) should be required to ensure all operator crews have the necessary experience.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: 2 years would be more appropriate to re-establish either a PCC or BCC.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments: Not aware of any at this time.

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☒ No

   Comments: No other comments at this time.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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: Santee Cooper

Lead Contact: Terry Blackwell

Contact Organization: Santee Cooper

Contact Segment: Transmission (1)

Contact Telephone: (843) 761-8000 ext. 5196

Contact E-mail: tlblackw@santeecooper.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Wayne Ahl	Santee Cooper	SERC	1
Glenn Stephens	Santee Cooper	SERC	1
Tom Abrams	Santee Cooper	SERC	1
Rene' Free	Santee Cooper	**SERC**	1

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments: While we agree, we also believe that this standard may not be the best place to provide for that limitation. Other processes exist to handle exceptions and there may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). As long as there are no restrictions in the ability to communicate with the GOPs, there should not be an issue.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: The key term is "backup functionality". We believe it's quite reasonable and an appropriate time period to have the backup plan implemented and backup functionality in operation.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

Comments: To have the backup plan implemented and backup functionality in operation in a two to three hour period is quite reasonable in our opinion. We do believe that it should be at least two hours but perhaps no more than three hours. Smaller entities that need a larger physical separation between control centers will need at least two hours. In most cases, three hours should be the limit.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: We believe that should lbe left to the individual company and their corporate procedures. If you require it, it could unnecessarily introduce reliability problems to the real-time system.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments: We believe that 6 months is reasonable for a plan. We do not believe it is reasonable to expect full recovery in 6 months.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: We are unsure as to the definition of what starts the transition period and what ends the transition period to the backup control center. We believe further detail is required.

Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure?

Regarding R4 - We believe the term "replicates" should be removed, as this may not be physically possible. Perhaps a distiction between types of functionality required would be more appropriate.

We certainly disagree with any thought process that would require continual staffing of the backup control center. If entities can invoke their backup plan and have backup functionality with two to three hours, this should be sufficient, especially given the odds of the number of times it will be needed.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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:	SERC OC Standards Review Group (Project 2006-04)
Lead Contact:	Jim Case
Contact Organization:	Entergy
Contact Segment:	1,3
Contact Telephone:	(870) 541-3908
Contact E-mail:	jcase@entergy.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Jack Kerr	Dominion Virginia Power	SERC	1
Sam Holeman	Duke Energy - Carolinas	SERC	1,3
Tim Lyons	Owensboro, KY Municipal Utilities	SERC	1,3
Roman Carter	Southern Company	SERC	1,3
Jerry Tang	Municipal Electric Authority of GA	SERC	1,3
John Neagle	Associated Electric Cooperative, Inc	SERC	1,3
Glenn Stephens	Santee cooper	SERC	1,3
Wayne Ahl	Santee Cooper	SERC	1,3
Pat Huntley	SERC Reliability Corporation	SERC	10
John Troha	SERC Reliability Corporation	SERC	10
Larry Rodriguez	Union Power Partners	SERC	5

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject "BF Standards" by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: The SERC Operating Committee Standards Review Group (SOCSRG) believes that requirement 4.1.2, as written, is unenforceable and unmeasurable. There may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs. Alternatively ,there is a process to request waivers from NERC standards that could be used to solve this issue.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: The SOCSRG agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets.

   Other reasons for not including GOP's in this standard are:

   1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area.
   2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and
   3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☒ No

Comments: The term 'transition period' is ill-defined by the parenthetical expression that follows it. This leaves the SOCSRG unable to render an opinion. The parenthetical expression included in R6 should be broken out, more precisely defined, and placed in the standard as a measure for R6.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: The SOCSRG believes R8.1 and R8.2 are not appropriate subrequirements of Requirement 8 since they pertain to required functionality in the transition period while R8 pertains to a requirement for a notification list. The SOCSRG also believes that all functional entities subject to this standard in its current form should have a two hour transition period. As currently written, R8.1 and R8.2 are essentially unmeasureable.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: The SOCSRG believes that R12 is more appropriate as a measure for R6 and the number of required hours to test the plan is immaterial to reliability

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: This requirement is construed as attempting to give an entity an automatic waiver from R1 through R12 of this standard, following a catastrophic loss of its primary or backup control center (BUCC) that is a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC?

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the definition of what starts the transition period and what ends the transition period to the backup control center should be included in the standard.

Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure?

Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up.

A general comment by the SOCSRG that this standard, taken as a whole, appears to include "how" language. Requirements should be limited to "what" is required. Much of what is included in this standard appears to be "good utility practice" and not reliability requirements and should be stripped from the standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Jay Campbell	
Organization:	Sierra Pacific Power Co.	
Telephone:	775-834-3782	
E-mail:	jcampbell@sppc.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: To exempt GOP is a serious oversight for this standard. Specifically, for those GOP with a "centrally dispatched control center," they may control many stations with thousands of MW. If that central dispatch facilitiy were lost, how is interconnection reliability maintained without a backup control center? It's not.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: By allowing a six hour transition period,the standard basically is saying that a BA's ACE is unimportant for that time period. The old requirement of 1/2 hour should be maintained.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☐ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Rich Salgo	
Organization:	Sierra Pacific Resources Transmission	
Telephone:	775-834-5874	
E-mail:	rsalgo@sppc.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☒ No

   Comments: I agree with the concept of limiting the applicability, but I disagree with the relationship made to "Critical Assets", which I assume are those that are determined pursuant to CIP-002. Given the wide industry debate about CIP Critical Assets, I don't believe this will be a stable enough parameter upon which to base the need for BUCC's. As an alternative, perhaps the restriction should be to "TO's with control of Facilities with defined IROL's or SOL's".

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: The suggestion that Generating plants would need to have backup control centers is not financially feasible for the industry. The potential benefit of such a move would be minimal, if any. I'm pleased that the SDT did not pursue that direction.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: Most entities target 30-60 minutes as the time frame to start up their backup centers. Allowing two hours is appropriate.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

Comments: I don't disagree with 6 hours for BA's and TOP's as a Requirement, although, I believe the industry entities can do much better than this.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments: This is a good idea. Having to operate through 1 or more hourly ramp periods is a reasonable test of functionality.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☐ No

Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments: Not aware of any.

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☐ Yes

☐ No

Comments:
Use of "Plan", "Process" and "Procedure": I found myself a bit confused as to the terminology used here. The Standard starts out by defining that there shall be an Operating Plan for the backup center, which is to include a number of items. Later, the Standard introduces the terms "Operating Process" (R1.4 and R1.5) and even "Operating Procedure" (R8.1, R8.2). Many will interpret these terms to be synonymous unless there is some distinction provided in the Standard.

R9 Annual Review and Approval by a "manager": This term seemed a bit loose to me as I reveiwed the Standard. As it is not a defined term, it is left open to interpretation as to what level individual can act as the "manager". Perhaps there should be some clarification such as "…a manager having functional responsibility for Control Center Operation".

R10 Dependency Upon Primary Control Center: This Requirement prohibits any dependency upon the primary center for any aspect of the backup center operation. Such a strict Requirement may necessitate a transition period to achieve compliance. Most BUCC operations have some level of dependency upon the primary, and we strive to minimize that. The BUCC will likely have a reduced, but adequate, level of functionality if the primary were to be completely destroyed, but might have far greater capability if some of the primary control center facilities remain active. Note that this Standard does not specifically prescribe how much visiblity or functionality the BUCC must have.

Document Simplification Suggestions: Since R1 describes the Operating Plan and its minimum included items, I would suggest moving the text of R8 into a sub-item of R1, as R1.7. The draft R8 talks about another item that is to be included in the Operating Plan.

The sub items R8.1 and R8.2 don't seem to bear any relationship to the parent R8. These Requirements are for situational awareness if the implementation of the BUCC operation is to last more than 2 hours, and they fit better as sub-items under R7, which speaks to the transition period. I'd therefore suggest moving these under R7 as R7.1 and R7.2.

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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:	Southern Company - Transmission
Lead Contact:	JT Wood
Contact Organization:	Southern Company Services, Inc.
Contact Segment:	1
Contact Telephone:	205-257-6238
Contact E-mail:	jtwood@southernco.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Marc Butts	Southern Company Services	SERC	1
Roman Carter	Southern Company Services	SERC	1
Steve Corbin	Southern Company Services	SERC	1
Shane Eaker	Southern Company Services	SERC	1
Rodney O'Bryant	Southern Company Services	SERC	1
David Harris	Southern Company Services	SERC	1
Mike Sanders	Southern Company Services	SERC	1

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: Southern Company: Southern believes that requirement 4.1.2, as written, is unenforceable and unmeasurable. A more reasonable way to limit the impact to smaller Transmission Operators (TOPs) might be for them to request a waiver to the standard through NERC's waiver process.

   Southeastern RC comment: Without the TOP and BA, the function of the RC ceases to exist. All physical control of the Bulk Electric System ceases to exist without a TOP or BA in place. The RC does not have physical controls of the grid. The TOP and BA can function and maintain reliability without the existence of a RC.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☒ No

   Comments: Southen Company: We agree with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function.

   Southeastern RC comment: With a GOP having a centrally located dispatch control center, all control of the gernators are at one location. With the loss of this center and no backup facilties, the BA could not meet standards nor maintain reliability as the pure BA does not have physical control of the generators.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☒ No

Comments: Southern Company: The term "transition period' in the parenthetical is not sufficiently defined and could possibly leave the reader with an ambiguous meaning. The parenthetical expression included in R6 should be broken out and placed in the standard.

Southeastern RC comment: Agrees with this.

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Southern Company: We believe R8.1 and R8.2 are not appropriate subrequirements of Requirement 8 because the subject matter in 8.1 and 8.2 differ from the content contained in 8. Southern believes that all functional entities subject to this standard in its current form should have a two hour transition period. R8.1 and R8.2 are essentially unmeasureable.

Southeastern RC comment: Same answer as 1 (Without the TOP and BA, the function of the RC ceases to exist. All physical control of the Bulk Electric System ceases to exist without a TOP or BA in place. The RC does not have physical controls of the grid. The TOP and BA can function and maintain reliability without the existence of a RC)

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

☒ Yes

☒ No

Comments: Southern Company: Southern believes that R12 is more appropriate as a measure for R6 and the number of required hours to test the plan is immaterial to reliability. There seems to be an emphasis on "two hours" here. The real empahsis should be on each applicable entity performing an adequate test of their backup facility.

Southeastern RC comment: Agrees with this.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

☐ Yes

☒ No

Comments: Southern Company: This requirement can be interpreted as attempting to give an applicable entity an automatic waiver from R1 through R12 following a catastrophic loss of its primary or backup control center (BUCC) under a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC?

Southeastern RC comment: The answer is no, because the moment the primary center is lost, the RC, BA or TOP are out of Compliance. Thus to meet compliance, an entity would be required to have one primary and two backup centers. A lot of detail is lost in this requirement. It should state upon the loss of the primary center the RC, BA, or TOP are exempt from six (6) until a plan can be developed for an additional backup facility. The plan should include a backup center.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

☐ Yes

☒ No

Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

☒ Yes

☐ No

Comments: Southern Company: There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the

definition of what starts the transition period and what ends the transition period to the backup control center should be made more clear in the standard.
Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure?
Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up.

Southern Company EMS Services: We have concerns where an entity's current EMS system would not be compliant with the proposed standard, there should be adequate lead time for entities to make changes to their infrastructure to become compliant. Therefore, we would recommend an implementation plan to be a minimum of 2-3 years for this to occur.
How does this standard address computer infrastructure which can be geographically separate from the control centers and backup facilities?
If and when an event occurs, and one of the redundant sites is lost, what is the impact to compliance?

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Operating Reliability Working Group (ORWG)	
Organization:	Southwest Power Pool	
Telephone:	501-614-3241	
E-mail:	rrhodes@spp.org	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: Operating Reliability Working Group (ORWG)

Lead Contact: Robert Rhodes

Contact Organization: Southwest Power Pool

Contact Segment: 2

Contact Telephone: 501-614-3241

Contact E-mail: rrhodes@spp.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Brian Berkstresser	Empire District Electric	SPP	1,3,5
Scott Frink	Kansas City Power & Light	SPP	1,3,5
Allen Klassen	Westar Energy	SPP	1,3,5
Paul Lampe	City Power & Light (Indpendence, MO)	SPP	1,3,5
Mike Lucas	Kansas City Power & Light	SPP	1,3,5
Kyle McMenamin	Southwestern Public Service	SPP	1,3,5
Robert Rhodes	Southwest Power Pool	SPP	2

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☐ Yes

   ☒ No

   Comments: We do not agree with the wholesale exclusion of all TOPs without Critical Assests or IROLs from the requirement of maintaining some semblance of backup functionality. We believe they should at a very minimum be required to maintain communication with their Reliability Coordinator. Therefore provisions should be made in the standard to include such a requirement.

   Relatedly, should the SDT give consideration to an exclusion for small BAs?

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: We believe that as a bare minimum GOPs that have a significant impact (total output of 100 MW or more) on the BES should be requried to maintain communications with its host BA.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: Since Reliability Coordinators are currently required to adhere to a transition period of 1 hour, why shouldn't we maintain the 1-hour transition period requirement?

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

Comments: The transition plan should be a constant 2 hours for BAs and TOPS. This would then eliminate the need for R8.1 and R8.2.

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☐ Yes

   ☒ No

   Comments: We would propose two hours quarterly.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: In Requirement 9 add the following phrase after manager: …responsible for the operation of the primary control center.

   We would suggest that R2 be expanded to require copies of the Operating Plan be shared with all entities/locations having an active role in the plan.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Stephen Joseph	
Organization:	Tampa Electric Co.	
Telephone:	813-630-6510	
E-mail:	sjjoseph@tecoenergy.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments:

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☒ No

   Comments:

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
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**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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: Operating Practices Subcommittee

Lead Contact: Ed Hulls

Contact Organization: WAPA

Contact Segment: 1,3

Contact Telephone: 970-461-7566

Contact E-mail: hulls@wapa.gov

Additional Member Name	Additional Member Organization	Region*	Segment*
Ed Hulls	WAPA	WECC	1,3
Greg Tillitson	CMRC	WECC	10
Paul Morland	CSU	WECC	1,3
Nick Zaber	WAPA	WECC	1,3
Rich Hydzik	AVA	WECC	1,3
Julie Reichle	NWMT	WECC	1,3
Mike McGowan	NWMT	WECC	1,3
Steve Ashbaker	WECC	WECC	10
Steve Rueckert	WECC	WECC	10

*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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments: As long as the requirements in this standard are applicable to any transmission operator whose systems can impact reliability of the BES and not just registered TOPs.

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☐ Yes

   ☒ No

   Comments: The Centrally controlled GOPs have to have a plan to operate if they lose their central control center.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: If the assumption applies to the implementation or testing operations of the backup center and not each individual.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: 6 months is reasonable and makes its clear of the requirement that has not been available in the past.

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments: Not aware of any at this time

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☒ Yes

   ☐ No

   Comments: Clarity needs to be added to R 9.1 regarding the definition of "communication protocal"? For example, entities do not want to have to update the operating plan for changes such as an RTU communication protocol.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standard for Backup Facilities (Project 2006-04)

Please use this form to submit comments on the 1st draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 7, 2008**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "BF Standards" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Terri Eaton	
Organization:	Xcel Energy Services Inc.	
Telephone:	303-273-4878	
E-mail:	terri.k.eaton@xcelenergy.com	
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**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☒ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	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

The Backup Facilities Standard Drafting Team (SDT) is submitting these questions as part of its initial effort in revising EOP-008. Extensive revisions have been made to the existing standard. Many of these changes are a direct result of comments received from industry and from FERC Order 693.

The SDT is attempting to come up with practical limits as to which Transmission Operators (TOPs) need to be covered by this standard. This is to avoid placing undue burdens on small entities that would not have a deleterious effect on the reliability of the Interconnection. In that same vein, the SDT is allowing TOPs and BAs to provide needed backup functionality through third-party contract services. Again, this is an effort to reduce the burden on these entities without adversely impacting reliability.

The SDT has not included the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard. This position is in conflict with a directive in FERC Order 693. The SDT has discussed this issue at length and has been unable to come up with a reliability-based reason for centrally dispatched GOP inclusion. However, this position will need to be defended at FERC when this standard is filed. Along those lines, the SDT is working on a position paper outlining the reasons for this approach. A specific question has been included on this topic with a direct request for inputs from GOPs. In general, the SDT must provide an alternative approach that presents an equally effective and efficient solution to the one proposed in FERC Order 693. This could include items such as suggesting strengthening other standards, presenting business practices that may be followed now that would preclude the need for a backup control center, lesser cost alternatives, etc.

The SDT has also established timeframes for when backup capability must be available. These time frames are different for Reliability Coordinators (RCs) versus TOPs and BAs. Specific questions asking for feedback on these times have been included below. In addition, questions related to times involved for testing and re-establishment of primary/backup capability have been raised.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this revised standard. Accordingly, we request that you include your comments on this form and e-mail to sarcomm@nerc.net with the subject “BF Standards” by **March 7, 2008**.

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. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

   ☒ Yes

   ☐ No

   Comments:

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

   ☒ Yes

   ☐ No

   Comments: XES agrees with the drafting team that there are other means to address loss of a centrally dispatched generation control center besides requiring the burden and expense of back-up facilities. In many if not most cases the applicable Balancing Authority is fully capable of dispatching generation units directly in the event a centrally dispatched generation control center becomes inoperable making a backup control center for the generation dispatch function unnecessary.

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments: The provision should be revised to clarify whether the two-hour testing requirement is cumulative over the course of a year or whether the two-hour test is to be achieved over the course of two consecutive hours.

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

   ☒ Yes

   ☐ No

   Comments:

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

   ☐ Yes

   ☒ No

   Comments:

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

   ☐ Yes

   ☐ No

   Comments:

Consideration of Comments on First Draft of Standard for Backup Facilities (Project 2006-04)

The Backup Facilities Standard Drafting Team thanks all commenters who submitted comments on the 1st draft of the Standard EOP-008-1. This standard was posted for a 30-day public comment period from February 7 through March 7, 2008. The standard drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were 45 sets of comments, including comments from 127 different people from more than 75 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 has revised the standard for a second posting. Changes have been made to applicability and requirements R1.1, R1.2, R1.3, R1.4, R1.4.1, R1.4.2, R1.5, R1.6, R1.6.1, R1.6.2, R1.6, R3, R4, R5, R6, R7, R8, R8.1, R8.2, R9, R10, R11, and R12.

Major changes included:

- A revision to the applicability of the Transmission Operator (Section 4.1.2). This was done to attempt to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV unless the Regional Entity deems them as a critical part of the Interconnection.
- Changing the transition timeframes so that they are equivalent for all applicable entities. (R1.5)
- A short description of what needs to be in the Operating Process. (R1.6)
- A clarification to Requirements R4 and R5 as to when backup is required.

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 SAR can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Backup_Facilities.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 Vice President and 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 Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

116-390 Village Boulevard
Princeton, New Jersey 08540-5721
609.452.8060 | www.nerc.com

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.	Crystal Musselman		x		x		x					
2.	Anita Lee (G7)	Alberta Electric System Operator		x								
3.	William J. Smith	Allegheny Power	x									
4.	Ken Goldsmith (G9)	ALTW				x						
5.	Jason Shaver	American Transmission Company	x									
6.	John Neagle (G13)	Associated Electric Coop., Inc.	x		x							
7.	Rich Hydzik (G16)	AVA	x		x							
8.	J. Andrew Dodge (G1)	Baltimore Gas & Electric	x									
9.	William Keagle (G1)	Baltimore Gas & Electric	x									
10.	Ed Carmen (G1)	Baltimore Gas & Electric	x									
11.	Dave Rudolph (G9)	BEPC	x		x		x	x				
12.	Terry Doern	Bonneville Power Administration	x		x		x	x				
13.	Brent Kingsford (G7)	California ISO		x								
14.	John Appel	Chelan County PUD	x		x		x	x			x	
15.	Paul Lampe (G15)	City Power & Light (Independence, MO)	x		x		x					
16.	Greg Tillitson (G16)	CMRC										x
17.	Eduardo Paredes González	Comision Federal de Electricidad	x		x		x	x				
18.	Peter Yost (G10)	ConEd	x			x	x	x				
19.	Jeanne Kurzynowski (G8)	Consumers Energy Company			x	x	x					
20.	Paul Morland (G16)	CSU	x		x							
21.	Jalil Babik (G2)	Dominion Resources			x		x					
22.	Louis Slade (G2)	Dominion Resources			x		x					
23.	Ronald E. Hart (G2)	Dominion Resources			x		x					
24.	Ronald Hart (G10)	Dominion Resources, Inc.					x					
25.	Jack Kerr (1) (G13)	Dominion Virginia Power	x									
26.	Daniel Herring (G3)	DTE Energy			x	x	x					
27.	Don Boyer (G3)	DTE Energy — Merchant Operations			x	x	x					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
28.	Greg Rowland	Duke Energy	x		x		x	x				
29.	Sam Holeman (G13)	Duke Energy – Carolinas	x		x							
30.	Brian Berkstresser (G15)	Empire District Electric	x		x		x					
31.	Will Franklin (G4)	Entergy — System Planning						x				
32.	Jerry Stout (G4)	Entergy — System Planning						x				
33.	Edward J. Davis	Entergy Services, Inc.	x									
34.	Jim Case (G13)	Entergy Services, Inc.	x		x							
35.	Steve Myers (G7)	ERCOT		x								
36.	Sam Ciccone (G5)	FirstEnergy Corp.	x		x		x	x				
37.	Dave Folk (G5)	FirstEnergy Corp.	x		x		x	x				
38.	John Reed (G5)	FirstEnergy Corp.	x		x		x	x				
39.	Eugene Blick (G5)	FirstEnergy Corp.	x		x		x	x				
40.	John Stephens (G5)	FirstEnergy Corp.	x		x		x	x				
41.	Steve Lux (G5)	FirstEnergy Corp.	x		x		x	x				
42.	Bob Chambers (G5)	FirstEnergy Corp.	x		x		x	x				
43.	Mark L. Bennett	Gainesville Regional Utilities					x				x	
44.	Joseph Knight (G9)	GRE	x		x		x	x				
45.	Alessia Dawes	Hydro One Networks, Inc.	x		x							
46.	David Kiguel (G10)	Hydro One Networks, Inc.	x		x							
47.	Roger Champagne (G6) (G10)	Hydro-Québec TransÉnergie	x									
48.	Danielle Beaudry (G6)	Hydro-Québec TransÉnergie	x									
49.	Sylvain Clermont (G10)	Hydro-Québec TransÉnergie	x	x								
50.	Ron Falsetti (I) (G7)	Independent Electricity System Op.		x								
51.	Biju Gopi (G10)	Independent Electricity System Op.		x								
52.	Kathleen Goodman (I) (G10)	ISO New England		x								
53.	Matt Goldberg (G7)	ISO New England		x								
54.	Jim Cyrulewski (G8)	JDRJC Associates								x		
55.	Scott Frink (G15)	Kansas City Power & Light Co.	x		x		x					
56.	Mike Lucas (G15)	Kansas City Power & Light Co.	x		x		x					
57.	Eric Ruskamp (G9)	Lincoln Electric System	x		x		x	x				
58.	Donald E. Nelson (I) (G10)	MA Depart. of Public Utilities									x	
59.	Joseph DePoorter (I) (G9)	Madison Gas and Electric				x						
60.	Doug Rempel	Manitoba Hydro Energy Board	x		x		x	x				
61.	Robert Coish (G9)	Manitoba Hydro Energy Board	x		x		x	x				
62.	Tom Mielnik (G9)	MEC	x		x		x	x				
63.	Bill Phillips (G7)	Midwest ISO		x								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
64.	Jason L. Marshall (G8)	Midwest ISO		x								
65.	Terry Bilke (G9)	Midwest ISO		x								
66.	Carol Gerou (G9)	Minnesota Power	x		x		x	x				
67.	Larry Brusseau (G9)	MRO										x
68.	Michael Brytowski (G9)	MRO NSRS										x
69.	Jerry Tang (G13)	Municipal Electric Authority of GA	x		x							
70.	Michael Ranalli (G10)	National Grid	x			x						
71.	Tony Eddleman	Nebraska Public Power District	x		x		x					
72.	Randy MacDonald (G10)	New Brunswick System Operator		x								
73.	Jim Castle (G7)	New York ISO		x								
74.	Gregory Campoli (G10)	New York ISO		x								
75.	Ralph Rufrano (G10)	New York Power Authority	x			x	x	x			x	
76.	Guy V. Zito (G10)	Northeast Power Coordinating Council										x
77.	Lee Pedowicz (G10)	Northeast Power Coordinating Council										x
78.	Rick White	Northeast Utilities	x									
79.	Murale Gopinathan (G10)	Northeast Utilities	x			x						
80.	Julie Reichle (G16)	NWMT	x		x							
81.	Mike McGowan (G16)	NWMT	x		x							
82.	Diane Barney	NY State Dept. of Public Service									x	
83.	Stan Southers/Ellis Rankin	Oncor Electric Delivery Company	x									
84.	Brian Gooder (G10)	Ontario Power Generation, Inc.					x					
85.	Tim Lyons (G13)	Owensboro, KY Municipal Utilities	x		x							
86.	Robert Williams	PacifiCorp Grid Operations	x									
87.	Lauri Jones	Pacific Gas & Electric Company	x		x							
88.	Patrick Brown (G7)	PJM Interconnection		x								
89.	Patrick Brown (G11)	PJM Interconnection		x								
90.	Joe Willson (G11)	PJM Interconnection		x								
91.	Mike Bryson (G11)	PJM Interconnection		x								
92.	Al DiCaprio (G11)	PJM Interconnection		x								
93.	Phil Riley	PS Commission of South Carolina									x	
94.	Mark C. Wills	Sacramento Municipal Utility Dist.	x		x		x	x				
95.	Terry Blackwell (G12)	Santee Cooper	x									
96.	Wayne Ahl (G12) (G13)	Santee Cooper	x									
97.	Glenn Stephens (G12) (G13)	Santee Cooper	x									
98.	Tom Abrams (G12)	Santee Cooper	x									
99.	René Free (G12)	Santee Cooper	x									
100.	Wayne Guttormson (G9)	SaskPower	x		x							x

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
101.	Pat Huntley (G13)	SERC Reliability Corporation										x
102.	John Troha (G13)	SERC Reliability Corporation										x
103.	Jay Campbell	Sierra Pacific Power Company	x									
104.	Rich Salgo	Sierra Pacific Resources Transm.	x									
105.	Roman Carter (G13) (G14)	Southern Company Services, Inc.	x		x							
106.	J.T. Wood (G14)	Southern Company Services, Inc.	x									
107.	Marc Butts (G14)	Southern Company Services, Inc.	x									
108.	Steve Corbin (G14)	Southern Company Services, Inc.	x									
109.	Shane Eaker (G14)	Southern Company Services, Inc.	x									
110.	Rodney O'Bryant (G14)	Southern Company Services, Inc.	x									
111.	David Harris (G14)	Southern Company Services, Inc.	x									
112.	Mike Sanders (G14)	Southern Company Services, Inc.	x									
113.	Charles Yeung (G7)	Southwest Power Pool		x								
114.	Robert Rhodes (G15)	Southwest Power Pool										x
115.	Kyle McMenamin (G15)	Southwestern Public Service	x		x		x					
116.	Stephen Joseph	Tampa Electric Company	x		x		x					
117.	Larry Rodriguez (G13)	Union Power Partners					x					
118.	Brian Evans-Mongeon (G10)	Utility Services, LLC						x				
119.	Jim Haigh (G9)	WAPA	x					x				
120.	Ed Hulls (G16)	WAPA	x		x							
121.	Nick Zaber (G16)	WAPA	x		x							
122.	Barb Kedrowski (G8)	We Energies			x	x						
123.	Steve Ashbaker (G16)	WECC										x
124.	Steve Rueckert (G16)	WECC										x
125.	Allen Klassen (G15)	Westar Energy	x		x		x					
126.	Neal Balu (G9)	WPS			x	x	x	x				
127.	Pam Oreschnick (G9)	Xcel Energy Services, Inc.	x		x		x	x				
128.	Terri Eaton	Xcel Energy Services, Inc.	x		x		x	x				

I – Individual
G1 – Baltimore Gas & Electric
G2 – Dominion Resources Services, Inc.
G3 – Duke Energy
G4 – Entergy – System Planning & Operations

G5 – FirstEnergy Corp.
G6 – Hydro-Québec TransÉnergie
G7 – ISO/RTO Council Standards Review Committee
G8 – Midwest ISO
G9 – Midwest Reliability Organization
G10 – NPCC Regional Standards Committee
G11 – PJM Interconnection
G12 – Santee Cooper
G13 – SERC OC Standards Review Group
G14 – Southern Transmission
G15 – SPP Operating Reliability Working Group
G16 – WECC Reliability Coordination Comments Work Group

Index to Questions, Comments, and Responses

1. The SDT has attempted to limit the applicability provisions for Transmission Operators in this standard. Do you agree with this limitation? If not, please provide the reasons and alternatives.

Summary Consideration: After reading the comments for Question #1, there appeared to be some confusion as to what the SDT was asking. Some commenters seemed to think the SDT was asking whether all TOPs should be excluded from this standard. That was definitely not the case. Rather, the SDT was asking if the industry agreed with the Critical Asset/IROL exclusion criteria included in Section 4.1.2 which would potentially exclude a limited number of TOPs from compliance with this standard. There were also a number of commenters that understood the SDT's question and clearly addressed it. In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT has decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, we propose to replace the IROL/Critical Asset exclusion criteria with language that is intended to require only those TOPs who operate Transmission Facilities that will have a material impact on reliability of the Bulk Electric System. The language shown below identifies the TOPs that would be required to comply with the standard:

4.1.2 Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES).

By including this new language in Section 4.1.2 of the standard this will require all entities registered as a TOP that have a material impact on the Bulk Electric System to have back-up functionality that ensures it has the same capability as it does with its primary facility and also the ability to remain in compliance with all with applicable reliability standards. However, if a Regional Entity/NERC demonstrates that an excluded TOP does have a material impact on the Bulk Electric System, then that TOP would have to comply with this standard.

Some commenters agreed that smaller TOPs may not need the same back-up functionality as larger TOPs. While the SDT has proposed new language for determining which TOPs must comply with this standard, it is also possible to further address these issues in the registration process and possibly through a revision to the Functional Model.

Some commenters referenced issues related to local control centers (LCCs) that are not registered with NERC as a TOP. Since the TOP is the registered entity, it is responsible for its compliance, and that of the LCCs under it, with standards that are applicable to it under the TOP function. The SDT is confident that we have addressed this issue as much as we can in the standards development process in Requirement R3 of the draft standard. If there are still issues related to what an LCC and its registered TOP are required to comply with, this is best handled in the registration process and possibly through a revision to the Functional Model, and not through the standards development process.

In summary, this standard would require RCs to have a full back-up facility, and BAs and applicable TOPs to have full back-up functionality.

#1 – Commenter	Yes	No	Comment
Allegheny Power		x	All control centers (Generator Operator or Transmission Owner (LCC) that control facilities via an EMS, GMS, etc. should comply with a Backup Facility criteria. That criteria may be in the form of a NERC Standard or a set of RTO/ISO requirements. In the case where a set RTO/ISO requirements are

#1 – Commenter	Yes	No	Comment
			used for control centers that are not Transmission Operators, those requirements should meet a minimum criteria established in a NERC Standard to guarantee uniformity on Bulk Electric System.
Entergy – System Planning		x	The attempt to limit the Transmission Operators subject to this standard opens many more questions and issues that are not addressed. The argument could also be made by some BAs that they have no critical assets or other reliability impact and thus desire an exclusion.
Hydro Québec/TransÉnergie		x	This standard should apply to all RCs, BAs, and TOPs. If an entity is registered as a TOP, their transmission system is part of the BES. The intent of providing backup facilities is to ensure the BES continues to be controlled and monitored.
IESO ISO New England ISO/RTO Council		x	This standard should apply to all RCs, BAs, and TOPs as the requirements so stipulate. We are therefore unclear on the basis of this question. The intent of providing backup capability/facilities is to ensure the BES continues to be controlled and monitored to balance load-generation-interchange, maintain frequency within acceptable range and loading on transmission network within SOLs and IROLs. BA, TOP and RC are the operating entities that are responsible for these tasks and hence must provide backup facilities to ensure continued control and operation. However, if the question is to address the specific provision in the Applicability Section, viz: "Transmission Operator with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits (IROLs).", then our comment would be that the provision should stops at "Critical Assets" since R1.2 in CIP-002-1 clearly stipulates that Critical Assets are those needed to support the reliable operation of the BES, which generally includes monitoring and operating to within IROLs and SOLs. Tying the provision to "with defined IROLs" would allow TOPs that monitors and control SOLs, and deploy/operate BES facilities that could affect BES reliability to be excluded from this standard, which in our view is unacceptable since SOL could become IROL any time as system conditions change.
Madison Gas and Electric		x	This standard should apply to all RCs, BAs, and TOPs. Any loss of primary control center may have a hugh effect on the BES. All TOPs should be required and if they believe they should not be, then the TOP should request

#1 – Commenter	Yes	No	Comment
			a waiver from NERCie, if the TOP only had a small radio fed transmission system.
Manitoba Hydro Energy Board		x	The TOP is as responsible as any entity in operating the BES, therefore their facilities are as important to the reliable operation of the BES as an RC or BA. I fail to see how the applicability is limited by the statement in the applicability section 4.1.2, any TOP with an EMS/SCADA system has critical assets and needs to protect against the loss of those assets.
Midwest ISO		x	This standard should apply to all RCs, BAs, and TOPs. If an entity is registered as an TOP, their transmission system is part of the BES. Any part of the BES could become limited by an IROL under certain conditions. Furthermore, these entities are responsible for identifying their own Critical Assets and IROLs. Thus, this is equivalent to letting a given TOP decide if a standard applies to them. Letting a responsible entity determine if a standard applies to them is a form of self-regulation. This is really a registration issue that should be determined by the Regional Entities. If the RE determines an entity meets the TOP registration criteria, then that entity should be subject to the same standards as any other TOP.
Midwest Reliability Organization		x	No, according to the NERC glossary of terms the transmission operator is that "… entity (which is responsible) for reliability of its "local" transmission system, and that operates or directs the operation of the transmission facilities." Taking this into account, this standard speaks to the lost of these transmission facilities and how the transmission operator plans to handle these lost facilities. All transmission operators which operate Bulk Electric System should be applicable to this standard since bulk electric facilities, systems, and equipment which if destroyed, degraded, or otherwise rendered unavailable would affect the reliability or operability of the BES since the BES would no longer be capable of functioning. (Also, please note I am not referring to the lost of one transmission line or a generator but a loss of an entire "local" transmission system operated by a transmission operator.) Is it possible for a transmission operator to operate a transmission facility which is not included in the BES? If so, then perhaps this standard should not apply to them. Please give an example of a transmission operator who does not operate BES facilities?
PJM Interconnection		x	According to NERC's Statement of Compliance Registry Criteria (Revision 4.0), any entity responsible for the reliability of its "local" transmission

#1 – Commenter	Yes	No	Comment
			system, and that operates or directs the operations of the transmission facilities, and is directly connected to the bulk power system (>100 kv), is required to register as a TOP. As such, the loss of any TOP's primary control facilities could have a major impact on wider system reliability. Therefore, ALL registered TOPs should be included in this standard.
Sacramento Municipal Utility Dist.		x	All BES entities registered as TOPs should have the same requirements.
Response: After reading the comments for Question #1, there appeared to be some confusion as to what the SDT was asking. Some commenters seemed to think the SDT was asking whether all TOPs should be excluded from this standard. That was definitely not the case. Rather, the SDT was asking if the industry agreed with the Critical Asset/IROL exclusion criteria included in Section 4.1.2 which would potentially exclude a limited number of TOPs from compliance with this standard. There were also a number of commenters that understood the SDT's question and clearly addressed it. In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT had decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, the SDT has proposed to replace the IROL/Critical Asset exclusion criteria with language that is intended to require only those TOPs who operate Transmission Facilities that will have a material impact on reliability of the BES. The language shown below identifies the TOPs that would be required to comply with the standard: 4.1.2. Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES). By including this new language in Section 4.1.2 of the standard, this will require all entities registered as a TOP that have a material impact on the BES to have back-up functionality that ensures it has the same capability as it does with its primary facility and also the ability to remain in compliance with all with applicable reliability standards. However, if a Regional Entity/NERC demonstrates that an excluded TOP does have a material impact on the BES, then that TOP would have to comply with this standard. Some commenters agreed that smaller TOPs may not need the same back-up functionality as larger TOPs. While the SDT has proposed new language for determining which TOPs must comply with this standard, it is also possible to further address these issues in the registration process and possibly through a revision to the Functional Model. In summary, this standard would require RCs to have a full back-up facility, and BAs and applicable TOPs to have full back-up functionality.			
American Transmission Company		x	ATC does not understand the SDT's motivation for limiting the scope of the proposed Standard to Transmission Operators (TOPs) with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits. The proposed accountability is a step backward from existing Reliability Standards and has the potential to expose the grid to greater reliability related risks following the loss of a non-applicable TOP's control center.

#1 – Commenter	Yes	No	Comment
			What justification does the SDT provide to make such a major change to this reliability standard?
Response: In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT had decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, the SDT proposes to replace the IROL/Critical Asset exclusion criteria with language that is intended to require only those TOPs who operate Transmission Facilities that will have a material impact on reliability of the BES. The language shown below identifies the TOPs that would be required to comply with the standard: 4.1.2. Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES).			
Baltimore Gas and Electric		x	Under the Applicability Section 4.1.2; What is the official definition of "Critical Assets"? Are these the same as the Critical Assets identified in the CIP-002? There are situations where the Transmission Operators and the Transmission Owners are not the same entitiy. In this case, the Transmission Owner is responsible for identifying their Criitical Assets under CIP-002 and there is no requirement that they share this list with their Transmission Operator. In this relationship, how would the Transmission Operator know what the Critical Assets are in their transmission zone? Does the statement "with control of Facilities that are designated as Critical Assets" imply that this standard does not apply to Transmission Operators that do not have physical control of Facilities that are designated as Critical Assets? As written, this standard would not apply to Transmission Owners who perform the Local Control Center function under the direction of a NERC registered Transmission Operator (although the LCC may actually control the facility designated as critical or associated with the IROL).
Bonneville Power Admin.	x		If TOs have IROLs they must have the capablity to monitor critical lines & transmission paths within critical time periods (20 minute for stability, 30 minutes for thermal). This may add the need for B/U control center. Many smaller TOs with limited tranmission do not impact the BES.
Duke Energy Corp.		x	The limitation doesn't make sense and would be difficult to enforce, since Critical Asset lists and defined IROLs will change over time. Applicability should be on the basis of NERC Registration, to avoid an ongoing tangled

#1 – Commenter	Yes	No	Comment
			mass of exceptions. For example, a TOP with control over a limited number of facilities should still be required to provide backup functionality, however backup functionality can be provided in other ways than constructing backup facilities.
Gainesville Regional Utilities		x	In some cases an entity categorized as a transmission operator may be an entity that has a radial transmission line through their system and there is no nee for either a control center or a back up. They still need a back up plan.
Santee Cooper	x		While we agree, we also believe that this standard may not be the best place to provide for that limitation. Other processes exist to handle exceptions and there may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs.
Sierra Pacific Resources Transm.	x	x	I agree with the concept of limiting the applicability, but I disagree with the relationship made to "Critical Assets", which I assume are those that are determined pursuant to CIP-002. Given the wide industry debate about CIP Critical Assets, I don't believe this will be a stable enough parameter upon which to base the need for BUCC's. As an alternative, perhaps the restriction should be to "TO's with control of Facilities with defined IROL's or SOL's".
SPP ORWG		x	We do not agree with the wholesale exclusion of all TOPs without Critical Assests or IROLs from the requirement of maintaining some semblance of backup functionality. We believe they should at a very minimum be required to maintain communication with their Reliability Coordinator. Therefore provisions should be made in the standard to include such a requirement. Relatedly, should the SDT give consideration to an exclusion for small BAs?

Response: In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT had decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, the SDT proposes to replace the IROL/Critical Asset exclusion criteria with language that is intended to require only those TOPs who operate Transmission Facilities that will have a material impact on reliability of the BES. The language shown below identifies the TOPs that would be required to comply with the standard:

4.1.2. Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES).

By including this new language in Section 4.1.2 of the standard this will require all entities registered as a TOP that have a material impact on the BES to have back-up functionality that ensures it has the same capability as it does with its primary facility and also the ability to remain in compliance with all with applicable reliability standards. However, if a Regional Entity/NERC demonstrates that an excluded TOP does have a

#1 – Commenter	Yes	No	Comment
material impact on the BES, then that TOP would have to comply with this standard. Some commenters agreed that smaller TOPs may not need the same back-up functionality as larger TOPs. While the SDT has proposed new language for determining which TOPs must comply with this standard, it is also possible to further address these issues in the registration process and possibly through a revision to the Functional Model. Some commenters referenced issues related to local control centers (LCCs) that are not registered with NERC as a TOP. Since the TOP is the registered entity, it is responsible for its compliance, and that of the LCCs under it, with standards that are applicable to it under the TOP function. The SDT is confident that we have addressed this issue as much as we can in the standards development process in Requirement R3 of the draft standard. If there are still issues related to what an LCC and its registered TOP are required to comply with, this is best handled in the registration process and possibly through a revision to the Functional Model, and not through the standards development process.			
Dominion Virginia Power Dominion Resources Entergy SERC OC Standards Review Group		x	Dominion Virginia Power (DVP) believes that requirement 4.1.2, as written, is unenforceable and unmeasurable. There may be a more reasonable way to limit the impact to smaller Transmission Operators (TOPs). This could easily be handled in the rules of registration for TOPs. Alternatively ,there is a process to request waivers from NERC standards that could be used to solve this issue.
DTE Energy		x	I do not agree with this limitation. I would agree with this aproach if there was one risk-based assessment methodology used by all Transmission Operator entities to identify their Critical Assets.
FirstEnergy Corp.		x	We do not agree with the limitations proposed in the applicability. We see the following reliability issues with these limitations: 1. It leaves it to the TOP to determine if the standard applies to him. The burden of determining applicability to these requirements should be the responsibility of the auditor. 2. If a TOP incorrectly determines that he is not responsible to have plans for backup functionality, his neighbors in the BES control system may be in jeopardy. 3. If an entity is registered as a TOP, then every standard applies to him since his registration has already determined he has impact on the reliability of the Bulk Electric System.
Southern Company Services, Inc.		x	Southern Company: Southern believes that requirement 4.1.2, as written, is unenforceable and unmeasurable. A more reasonable way to limit the impact

#1 – Commenter	Yes	No	Comment
			to smaller Transmission Operators (TOPs) might be for them to request a waiver to the standard through NERC's waiver process. Southeastern RC comment: Without the TOP and BA, the function of the RC ceases to exist. All physical control of the Bulk Electric System ceases to exist without a TOP or BA in place. The RC does not have physical controls of the grid. The TOP and BA can function and maintain reliability without the existence of a RC.
Response: In response to the overwhelming majority of the comments expressing concern regarding the exclusion criteria, the SDT had decided to remove the IROL/Critical Asset exclusion criteria for TOPs. Instead, we propose to replace the IROL/Critical Asset exclusion criteria with the language that is intended to require only those TOPs who operate transmission facilities that will have a material impact on reliability of the bulk power system. The language shown below identifies the TOPs that would be required to comply with the standard: Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES). By including this new language in 4.1.2 of the standard this will require all entities registered as a TOP that have a material impact on the bulk power system to have back-up functionality that ensures it has the same capability as it does with its primary facility and also the ability to remain in compliance with all with applicable reliability standards. However, if a Regional Entity/NERC demonstrates that an excluded TOP does have a material impact on the bulk power system, then that TOP would have to comply with this standard.			
Avista Corporation			No comment.
Chelan County PUD	x		
Comision Federal de Electricidad WECC Operating Practices SC	x		As long as the requirements in this standard are applicable to any transmission operator whose systems can impact reliability of the BES and not just registered TOPs.
Hydro One Networks, Inc.	x		
MA Dept. of Public Utilities			No comment.
Nebraska Public Power District	x		
NY State Dept. of Public Service			No comment.
Northeast Utilities	x		
NPCC Regional Standards Cmte.			No comment.

#1 – Commenter	Yes	No	Comment
Oncor Electric Delivery Company	x		
PacifiCorp	x		
Pacific Gas and Electric Company	x		
PS Commission of South Carolina	x		
Sierra Pacific Power Company	x		
Tampa Electric Company	x		
Xcel Energy	x		
Response: Thank you for your comment. Note that in response to comments from other stakeholders, the SDT has revised the applicability section of the standard. Please see the Summary Consideration for this question.			

2. The SDT has decided not to include the Generator Operator (GOP) with a centrally dispatched control center as an applicable entity in this standard at this time. The SDT believes that there are other equally efficient and effective methods for the GOPs to continue to fulfill their role in preserving the reliability of the Interconnection following the loss of its control center. This position is contrary to a directive in FERC Order 693. The SDT will need to provide specific reasoning to FERC for adopting such an approach and is therefore, soliciting opinions from the industry. Do you agree with this approach? If not, please state the reasons and suggest an alternative. The SDT is particularly interested in receiving inputs from GOPs as to how they currently handle such a situation.

Summary Consideration: Care has been taken to consider and include comments on the original EOP-008-0 submitted by various industry groups as well as FERC from Order 693. However, the SDT does not feel that any reliability purpose would be served by including GOP's as applicable entities.

The primary issue of whether *centrally dispatched generation control centers* should be applicable entities to the EOP-008-1 standard is an issue of risk exposure to the reliable operation of the BES. The SDT believes the risk exposure does not merit the inclusion of GOP's in this standard for the following reasons:

1. The risk exposure for the loss of an RC's, BA's, or TOP's primary control center is far greater than for the loss of any one *centrally dispatched control center*. This greater risk is a function that each RC, BA, and TOP controls a definitive portion of the interconnection. The interconnection requires the command and control directives and signals from each RC, BA, and TOP to synchronize minute-to-minute operations within these operational zones. And when these RC, BA, and TOP control centers are lost, the key outputs of directives and communications are lost within that zone. In contrast, if GOPs operating generators from a *centrally dispatched generation control center* were to have to evacuate their control centers, the key output of energy from their controlled units is not lost. With the energy still being produced by the units there is no DCS event because a *centrally dispatched generation control* center is evacuated. Understandably, in some cases the directives and communications that permit load following capability of those units may be lost, but in other cases through direct data pathways and communication protocols between BA's and generating units there would not be a significant impact to unit load following and ancillary service operations.

2. In the case where the BA may not have the data links and communication protocols to sustain load following from the units being controlled by a compromised *centrally dispatched generation control center*, the BA should be able to quickly assess that it had some units no longer following dispatch signals. At that point, the BA needs to handle this situation as it does similar situations each day when units are slow to respond, fail to start, or for one reason or another fail to follow control signals. In such a case, the BA goes to the next set of resources under its control and directs them to fill the void. So in contrast to where a TOP and BA have only one RC to turn to for RC directives, a BA or TOP could look to any number of GO's and GOP's to resolve a BES operating issue. As such, the SDT saw the mitigation of this risk as really an economic issue (moving to the next marginal unit) rather than an operating emergency.

3. Additionally, the risk created by the potential loss of a *centrally dispatched generation control center* is further mitigated by the all too typical situation that such GOPs operate units throughout the interconnection in multiple BAs. As such, the risk is spread amongst multiple BAs and TOPs each of which have their own diverse selection of alternative GOs and GOPs to address the potential operating issue.

An additional reason for why the SDT has not included *centrally dispatched generation control centers* into the applicability of this standard is that there is no such defined role in the NERC Functional Model. The SDT grappled with whether a *centrally dispatched generation control center* might be an entity that controlled a particular percentage of any one BA's designated resources (how is that tracked?), or controlled enough assets to have a particular impact to the BES's frequency (but at what dispatch point?). Bottom-line: there are far too many permutations of what a *centrally dispatched generation control* center could be. The end result of including such an ill-defined term into the applicability of EOP-008-1 is that too easily plants with multiple units at a single station might suddenly have to become compliant to this standard where in many cases the physical controls in their control rooms would be hard to replicate at an off-site facility.

The SDT believes strongly that a combination of the strengthening of requirements for RCs, TOPs, and BAs in the revised EOP-008-1 (see draft standard) as well as requirements in other, existing standards, adequately and sufficiently address the issue of GOP accountability.

Conclusion:

The SDT is recommending not to include GOPs in this list of applicable Responsible Entities, even those with centrally dispatched generation control centers, as adequate and sufficient concerns for the reliability of the BES are met within this and other standards and the exclusion of the GOP in EOP-008-1 is not detrimental to reliability or maintaining situational awareness of the BES. To include the GOP as an applicable entity in EOP-008-1 would not promote reliability and would simply create redundancy in the standards, a position that the NERC Reliability Standards Development Work Plan is striving to eliminate.

#2 – Commenter	Yes	No	Comment
Allegheny Power		x	See comment to question #1.
American Transmission Company		x	Generation is critical to the reliable operation of the BPS and should be included. ATC believes that the a more appropriate exemption could be based on the MW controlled by the GOP. ATC may be open to changing its position on this issue if strong information is presented to support this position.
Bonneville Power Admin.		x	A GOP must provide support to the BA to meet BAL standards during adverse power system conditions even when their primary control center is destroyed or not funcational. Other options may be practical as long as they meet the reliablity needs and meet NERC and regional standards.
DTE Energy		x	As energy markets mature and more generation assets are operated from central control centers, it is imperative for grid reliability, security, and stability that GOPs be able to fulfill their roles. Not having GOPs identified as applicable entities to a reliability standard addressing loss of control center functionality misses the intent of this standard.
Duke Energy Corp.		x	As FERC noted in Order No. 693, generator operators who have operational

#2 – Commenter	Yes	No	Comment
			control over significant amounts of generation are important to the reliability of the Bulk Power System. As such they should provide backup capabilities that are independent of the primary control center, can operate for a prolonged period of time, and provide for a minimum functionality to replicate the critical reliability functions of the primary control center. The reason BAs are required to have backup functionality is that BAs have direct communications (both data and voice) with generator sites and generator personnel. These are the front lines of operational situations. It is vital that we maintain these links in both normal, emergency conditions, and backup mode conditions.
FirstEnergy Corp.		x	We do not agree with the exclusion of a GOP with a centrally dispatched control center from the applicable entities in this standard. GOPs with responsibility for many units play an important role in the reliable operation of the BES. These GOPs should have business continuity plans. The bottom line is this: If it is a control center, and it has impact on the BES, it must be responsible for providing a way to backup its control center. We suggest adding the "Generator Operator" to the Applicability section of the standard, and adding "Generator Operator with centrally dispatched control centers" to requirements R1, R2, R5, and R7 through R13.
Gainesville Regional Utilities		x	
Midwest Reliability Organization		x	The SDT should include the Generator Operator within this standard especially if GOP can efficiently and effectively fulfill their role in preserving the reliability of the interconnection following the loss of the GOP's control center.
Sierra Pacific Power Company		x	To exempt GOP is a serious oversight for this standard. Specifically, for those GOP with a "centrally dispatched control center," they may control many stations with thousands of MW. If that central dispatch facilitiy were lost, how is interconnection reliability maintained without a backup control center? It's not.
Response: The SDT has considered these insights but has decided to continue to not have this standard applicable to "centrally dispatched generation control centers" for the reasons stated in the Summary Consideration for this question.			
Manitoba Hydro Energy Board		x	The GOP still needs to have a plan to continue its operations should they loose control centre functionality. The GOP may not be required to meet every requirement in the standard but they should have a plan to continue operations as per Requirement 1.
Midwest ISO		x	Standards are not supposed to define the "how" but rather they are supposed to define the "what". The SDT is focused on the "how". Within this very

#2 – Commenter	Yes	No	Comment
			question, the SDT acknowledges that there are other equally effective and efficienct methods for the GOPs to continue to fulfill their role in preserving reliability. We agree that is true, however, the SDT needs to define that role in preserving reliability. For instance, does the GOP need to have a plan to continue to dispatch the units in the event their central dispatch office fails? That plan could involve a number of solutions but the role is a focused on "what" needs to be accomplished.
PJM Interconnection	x		Although GOPs should not be required to maintain backup facilities, they should be required to have a backup communications plan under the COM standards.
Sacramento Municipal Utility Dist.		x	The Centrally controlled GOPs have to have a plan to operate if they lose their central control center. The impact to the BES could be the same as for a TOP.
WECC Operating Practices Subc.		x	The Centrally controlled GOPs have to have a plan to operate if they lose their central control center.
Response: The SDT has considered these insights but has decided to continue to not have this standard applicable to "centrally dispatched generation control centers" for the reasons stated in the Summary Consideration for this question.			
Pacific Gas and Electric Company		x	It is our understanding that the drafting teams are given specific direction in following the FERC Order 693 directive. If this approach had been followed then the team would respond to industry comments during the comment review period. This approach will further delay the standard implementation period.
Response: The SDT has tried to follow all of FERC's directives in its approach and has even spoken with FERC on this issue. It was the SDT's intent to explore other options with the broad base of the industry in the hopes of better addressing FERC's directives by asking this question. The SDT believes that the latest draft of EOP-008-1 and this comment report will help address FERC's concerns.			
SPP ORWG		x	We believe that as a bare minimum GOPs that have a significant impact (total output of 100 MW or more) on the BES should be requried to maintain communications with its host BA.
Response: The SDT believes that communication requirements should, and will, be handled in updated communications standards.			
Avista Corporation			No comment.
Baltimore Gas and Electric			No comment.
Chelan County PUD	x		Our generation facilities do have procedures for maintaining operations in the event of a loss of control system functionality, however this does not involve relocating to different facilities.
Comision Federal de Electricidad	x		

#2 – Commenter	Yes	No	Comment
Dominion Resources	x		In Order 693, FERC stated that the goal of the Reliability Standard is the continuation of reliable operations and the maintenance of situational awareness in the event that the primary control center is no longer operational. They further stated that "Other entities, including balancing authorities, transmission operators and centrally dispatched generation control centers, must provide for the minimum backup capabilities discussed above but may do so through other means, such as contracting for these services instead of through dedicated backup control centers." Given that the impact to reliability can vary depending on many diverse factors including; size of owner's asset base, NERC region, ISO/RTO or market rules, etc. we support the standard as written. Each region can, through its standards development process, place additional requirements if it deems necessary. Each RTO/ISO or market, through its stakeholder process, can also impose additional requirements upon its participants if it deems necessary. We further state that we support comments submitted by the SERC Operating Committee Standards Review Group (SOCSRG).
Dominion Virginia Power (1)	x		DVP agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). DVP believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets. Other reasons for not including GOP's in this standard are: 1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area. 2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and

#2 – Commenter	Yes	No	Comment
			3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location.
Entergy	x		Entergy agrees with and supports the SOCRG comments. The SOCSRG agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets. Other reasons for not including GOP's in this standard are: 1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area. 2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and 3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location
Entergy – System Planning	x		It appears to be appropriate to exclude centrally dispatched control centers for generators if they do not perform the functions of or part of the functions of a BA. The means for executing dispatch for a unit is a business decision If the dispatch operator is not performing any BA functions then there is no need for this standard to apply and whatever other standards or rules for maintaining communication between the unit and BA would apply.
Hydro One Networks, Inc.	x		We agree, assuming that for each Generation Station (GS), a GOP normally dispatches using a central control centre and a local control centre is located at the GS.
Hydro Québec/TransÉnergie NPCC Regional Standards	x	x	The applicability of this standard should be restricted to RC, BA, and TOP functions. The GOP's functions is to follow the directions of the BA for demand-

#2 – Commenter	Yes	No	Comment
Cmte.			energy balance and to ensure that applicable standards are complied to. It is essential that the BA, TOP, and RC have back-up facilities or provisions as specified in this standard but the GOP need not be included as long as the BA ensures that all BA functions are addressed by its back-up facilities. However, it is important that GOPs have a backup communication plan in place which must be provided to the appropriate reliability entity upon request.
IESO ISO New England	x		We agree that there are other equally effective and efficienct methods for the GOPs to continue to fulfill their obligation to generate, may it be for commercial reasons or reliability reasons. Generally speaking, the GOPs follow instructions of the BA, who is responsible for generation-load-interchange balance and maintaining system frequency. We agree that the standard does not need to include GOPs but the reasoning is that the BA will ensure dispatch instruction is provided to the GOPs to meet reliability standards. We recognize that some GOPs elect to set up control centres to operate a group of generators but this is a process set up for business efficiency only. Loss of a GOP operating centre does not hamper the capability of a BA communicating dispatch instructions directly to the generator/generating plant for continuous operation. However, it is important that GOPs have a backup communications plan in place which must be provided to the appropriate reliability entity upon request.
ISO/RTO Council			No comment.
Madison Gas and Electric	x		
MA Dept. of Public Utilities			No comment.
Nebraska Public Power District	x		
NY State Dept. of Public Service			No comment.
Northeast Utilities	x		An individual generator should not impact the reliability of the BPS.
Oncor Electric Delivery Company	x		
PacifiCorp	x		

#2 – Commenter	Yes	No	Comment
PS Commission of South Carolina	x		
Santee Cooper	x		Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). As long as there are no restrictions in the ability to communicate with the GOPs, there should not be an issue.
SERC OC Standards Review Group	x		The SOCSRG agrees with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators (GOP) with a central dispatch function as long as there are no gaps in the Reliability Function's ability to communicate with generation assets. Other reasons for not including GOP's in this standard are: 1.) the diverse nature and sheer number of generators, each already required to contribute to system reliability deficiencies (e.g., AVR response), as opposed to having only one Reliability Coordinator control room, for example. Any reliability deficiency caused by the loss of any single GOP control room or plant would simply be "made up" by other GOPs in the area. 2.) the various contributions to the Bulk Electric System of each generator must be taken into account. Some generators run when commercially contracted, others provide imbalance and regulation services, some are contracted to be "Must Run" units, yet others provide peaking capabilities. A "One Size Fits All" approach to requiring GOP BUCCs suggests inefficient and ineffective reliability requirements, and 3.) the "hands on" nature of large (500+MW) generating plants essentially prevents operation from a remote location.
Sierra Pacific Resources Transm.	x		The suggestion that Generating plants would need to have backup control centers is not financially feasible for the industry. The potential benefit of such a move would be minimal, if any. I'm pleased that the SDT did not pursue that direction.
Southern Company Services, Inc.	x	x	Southen Company: We agree with this approach. Generator Operators only follow directions issued by Reliability Functions - Reliability Coordinators (RC), Balancing Authorities (BA) and Transmission Operators (TOP). The SOCSRG believes that this standard does not need to apply to Generator Operators

#2 – Commenter	Yes	No	Comment
			(GOP) with a central dispatch function. Southeastern RC comment: With a GOP having a centrally located dispatch control center, all control of the gernators are at one location. With the loss of this center and no backup facilties, the BA could not meet standards nor maintain reliability as the pure BA does not have physical control of the generators.
Tampa Electric Company	x		
Xcel Energy	x		XES agrees with the drafting team that there are other means to address loss of a centrally dispatched generation control center besides requiring the burden and expense of back-up facilities. In many if not most cases the applicable Balancing Authority is fully capable of dispatching generation units directly in the event a centrally dispatched generation control center becomes inoperable making a backup control center for the generation dispatch function unnecessary.
Response: Thank you for your response.			

3. Requirement R6 — Do you think that the 2-hour transition time frame for Reliability Coordinators is appropriate? If not, please state the reasons and suggest an alternative.

Summary Consideration: Due to the questions raised, the SDT discussed the 2 hour timeframe at length and decided to retain it as described in the responses. One change was made to the requirements due to comments on this question:

R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running that is less than two hours.
R1.6: An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running. The Operating Process shall include:
R1.6.1. A list of all entities that will be notified when there is a change in operating locations.
R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.
R6. ~~Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.~~

#3 – Commenter	Yes	No	Comment
American Transmission Company		x	The proposed standard is weaker than the existing standard. ATC believes that the expected time should be one hour and, if exceeded, the plan should address how you are going to operate into the next hour. With a maximum time of 2 hours.

Response: There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:

- The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
- If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
- Realistic expectations for travel time in emergency conditions between the 2 centers.
- 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers.
- It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period.
- There is additional functionality required in this standard that wasn't there before.
- Organizational inertia in responding to the disaster.
- Cost benefit versus relative risk.
- R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.

#3 – Commenter	Yes	No	Comment
• It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Chelan County PUD		x	2 hours is a long time to be without a Reliability Coordinator function in the case of an emergency. I believe WECC plans to have the two Reliability Coordinators be a backup for each other with duplicate capabilities.
Response: Any entity may exceed standards. Due to the infrequency of events that require backup functionality, the SDT weighed the risk of losing the system during a critical event and the increased expense to organizations to meet shorter times for availability of backup capabilities.			
FirstEnergy Corp.		x	We suggest allowing provisions if the transition time takes longer than 2 hours. Similar to the current requirement for transition time from EOP-008-0 Requirement R1.8, we suggest rewording R6 as follows: "Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours. Interim provisions must be included in the plan when extenuating circumstances cause the transition to take longer than two hours."
Hydro One Networks, Inc.		x	
Hydro Québec/TransÉnergie ISO New England NPCC Regional Standards Cmte.		x	R6 needs additional "sub-bullet" to address what happens if the two hour time limit on the RC implementation of the backup plan is exceeded, similar to R8.1. It is not the transition time that is in focus here but the system reliability issues which could come up during the transition period which needs to be looked at closely.
IESO			The existing requirement R1.8 stipulates that the responsible entity shall have interim provisions if the implementation of the back-up capability plan will take longer than one hour. This draft standard appears to be relaxing this requirement by changing it to two hours. What is the basis for this change? We can continue to support the 1 hour requirement. However, if a time frame is to be removed, we recommend that the requirement be written such that the responsible entity shall provide operational capability at all times to ensure continuous operation, monitoring and control of the BES. In this case, it will be up to the responsible entity to demonstrate how its operation and control will continue during the transition period, such as by arranging other

#3 – Commenter	Yes	No	Comment
			entities to take over operation and control during that period.
Madison Gas and Electric		x	A "less than two hour" window to fully implement the backup plan and get backup functionality up and running is and can be a great task. There should be a provision that if their backup plan cannot be obtained within the two hour time frame.
MA Dept. of Public Utilities NY State Dept. of Public Service			R1.8 of the existing standard - while not placing an absolute deadline - envisions that the backup for the primary control facility of the reliability coordinator will be operational within one hour. There is no explanation as to why one hour is no longer a credible target timeframe for backup facility operation and needs to be doubled to two hours. A more rationale approach is to institute a plan that is expected to have the backup control facility functional within one hour, but if there are unforeseen circumstances that prevent operation within one hour, then there will not be a penalty associated with the second hour. An example would be that if the circumstances that disabled the primary control facilities made access to the backup difficult (e.g. flood that took out both the control center and surrounding roads) and it physically took longer than expected to reach the backup center, then there would be no penalty until two hours elapsed. However, if the event was a computer glitch and there were no significant obstacles to reaching the backup facilities, the one hour limit would control. If this proposal is unworkable from a standards drafting perspective, the standard should only allow a one hour transition time consistent with the existing standard instead of a two hour limit as proposed. The longer the system is outside of a standard operating mode there is a higher risk of serious reliability problems, which should not be allowed at the reliability coordinator level.

Response: There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:

- The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
- If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
- Realistic expectations for travel time in emergency conditions between the 2 centers.
- 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased

<table>
<tr><th>#3 – Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">reliability by reducing the risk of common events taking out both centers.
• It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period.
• There is additional functionality required in this standard that wasn't there before.
• Organizational inertia in responding to the disaster.
• Cost benefit versus relative risk.
• R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.
• It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.</td></tr>
<tr><td>Midwest ISO</td><td></td><td>x</td><td>Why did the standards drafting team increase the transition time frame from the one hour requirement in the existing standards? The drafting team needs to provide strong justification for this. If all RCs are currently meeting the standard one hour transition time frame in the existing standards, it is hard to fathom any reason to increase it.

Rather than specify a time frame for transition, we suggest alternative approach that is more justifiable. This approach would require the responsible entity to have minimal capability to meet the core set of applicable requirements during the transition. The drafting team will need to identify those core set of requirements.</td></tr>
<tr><td colspan="4">Response: The SDT does not agree with the complete removal of the time-frame for having backup functionality available, as it would require a manned hot-standby site, which would likely be an unnecessary expense due to the infrequency of events that require such extreme advance preparations.</td></tr>
<tr><td>Nebraska Public Power District</td><td></td><td>x</td><td>The 2-hour transition time is too restrictive - recommend a minimum of six hours.</td></tr>
<tr><td colspan="4">Response: The SDT believes that all RCs will be able to meet the 2-hour transition, as they are currently required to adhere to a 1 hour transition period.
There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:
• The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
• If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
• Realistic expectations for travel time in emergency conditions between the 2 centers.
• 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers.</td></tr>
</table>

#3 – Commenter	Yes	No	Comment
• It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
PJM Interconnection		x	The current, approved version of EOP-008, R1.8, states "Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility." We believe this time-frame is appropriate and in the best interest of system reliability, and therefore should not be relaxed.
Sacramento Municipal Utility Dist.		x	In the role of the RC, a 2-hour period is insufficient for required reliability covereage, and should be 1-hour.
SPP ORWG		x	Since Reliability Coordinators are currently required to adhere to a transition period of 1 hour, why shouldn't we maintain the 1-hour transition period requirement?
Response: The SDT extended the transition period to 2 hours to allow for the additional requirements that the new standard may have placed on the RCs. Nothing will prevent the RCs that have the ability to meet a shorter transition from doing so. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons: • The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it. • If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden. • Realistic expectations for travel time in emergency conditions between the 2 centers. • 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers. • It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.			

#3 – Commenter	Yes	No	Comment
• It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Dominion Resources Dominion Virginia Power Entergy SERC OC Standards Review Group Southern Company Services, Inc. Southeastern RC	x	x	The term 'transition period' is ill-defined by the parenthetical expression that follows it. This leaves us unable to render an opinion. The parenthetical expression included in R6 should be broken out, more precisely defined, and placed in the standard as a measure for R6.
Response: The SDT has re-written Requirement R6 as the new Requirement R1.5 with all entities having the same transition time and has removed the parenthesis to make it clear as to what was meant by transition period. R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running that is less than two hours. R6. ~~Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.~~			
Duke Energy Corp.	x	x	2 hours may be reasonable, however R6 is an ambiguous requirement. It is unclear exactly what the 2-hour transition period is referring to. It may not always be possible to establish an exactly precise point in time when primary control center functionality was lost. Likewise, it may not always be possible to define an exact point in time when backup functionality is "up and running". Furthermore, it is unclear whether this is just a requirement to have an appropriate 2-hour plan, or whether it is a requirement to always meet the 2-hour time limit, whether for tests or actual activation.
Response: Requirement R6 has been deleted and the transition issue is now handled in Requirement R1.5 R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running that is less than two hours. R6. ~~Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.~~			
Entergy – System Planning	x	x	It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. A statistical risk analysis would be ideal to determine this allowable time, if a valid model exists. If an arbitrary value is used, then an industry survey or something similar (experts/EPRI) may be appropriate.
Response: The SDT increased the transition time frame to allow RCs to meet any requirements that may have grown with the current draft of			

#3 – Commenter	Yes	No	Comment
the standard. The SDT used the EPRI document "Power System Backup Control Center Requirements, EPRI TR-103605, Project 2473-68, April 1994" and searched for other research. The EPRI document did not include timeframes for transition, and the SDT was unable to find other sources that discussed timeframes. Therefore, the SDT used the rationale listed in our response to ATC on this question. Please provide the source and title of any other research that you would like the SDT to consider in future drafts.			
ISO/RTO Council	x	x	The regulatory approved reliability standard currently requires that a responsible entity have interim provisions if the implementation of the back-up capability plan will take longer than one hour. This draft standard appears to be reducing the stringency of this requirement by changing it to two hours. What is the justification for this? Are there responsible entities experiencing difficulties meeting the requirement? If all responsible entities are currently compliant with the requirement, why increase the time frame? In fact, we recommend that time frame should not be considered. The entity should be responsible for meeting a core set of requirements at all times.
Response: The SDT increased the transition to the time frame to allow RCs to meet any requirements that may have grown with the current draft of the standard. The SDT does not agree with the complete removal of the time-frame for having backup functionality available, as it would require a manned hot-standby site, which would likely be an unnecessary expense due to the infrequency of events that require such extreme advance preparations. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons: • The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it. • If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden. • Realistic expectations for travel time in emergency conditions between the 2 centers. • 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers. • It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Midwest Reliability	x	x	Not sure, where did the 2-hour transition time frame come from? Is it

#3 – Commenter	Yes	No	Comment
Organization			reasonable to assume that 2 hours may not be possible? For example, what if a snow/ice storm of the century hits the control area in question? The ice storm renders the primary control center inoperable. Mobility to the backup control center is arrested due to massive snow fall. Is a Reliability Coordinator still reasonably expected to have the backup control center operational within 2 hours after the loss of the primary control center? The weather I describe is probable and it's planned for in designing facilities shouldn't we at least consider this situation as a possibility? To account for this possibility perhaps this time frame and the other time frames listed in this standard should be modified to allow the Compliance Monitor the option to arrest this requirement during natural destroyers or not prescribe a specific time period but say to operators you must make every foreseeable effort to transition as soon as possible.
Response: The SDT discussed the possibilities that might arise during actual events to prevent time-frames from being met. Rather than attempt to list all of the possibilities in the standard, the SDT determined that a violation of the time-frame would then use the appeal process and allow the RRO to determine if the violation was justified. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons: • The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it. • If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden. • Realistic expectations for travel time in emergency conditions between the 2 centers. • 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers. • It is assumed that the TOP and BA are still functioning and can operate on their own for a 2 hour time period. • There is additional functionality required in this standard that wasn't there before. • Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
Allegheny Power	x		See comment to question #1.
Avista Corporation	x		

#3 – Commenter	Yes	No	Comment
Baltimore Gas and Electric	x		
Bonneville Power Admin.	x		
Comision Federal de Electricidad	x		Because Reliability Coordinators have to be as soon as possibly ready to coordinate the different Control Areas.
DTE Energy	x		
Gainesville Regional Utilities	x		
Manitoba Hydro Energy Board	x		
Northeast Utilities	x		
Oncor Electric Delivery Company	x		
PacifiCorp	x		
Pacific Gas and Electric Company	x		
PS Commission of South Carolina	x		
Santee Cooper	x		The key term is "backup functionality". We believe it's quite reasonable and an appropriate time period to have the backup plan implemented and backup functionality in operation.
Sierra Pacific Power Company	x		
Sierra Pacific Resources Transm.	x		Most entities target 30-60 minutes as the time frame to start up their backup centers. Allowing two hours is appropriate.
Tampa Electric Company	x		
WECC Operating Practices Subc.	x		
Xcel Energy	x		
Response: Thank you for your response. Note that in response to comments from other stakeholders, the SDT has revised the wording of this requirement. Please see the Summary Consideration for this question.			

4. Requirement R7, R8.1, and R8.2 — Do you think the 2 to 6-hour time frame for applicable Transmission Operators and Balancing Authorities is appropriate? If not, please state the reasons and suggest an alternative.

Summary Consideration: Due to comments made by the industry to this question, the timeframes have been changed so that all entities now have the same 2 hour timeframe. Changes were made to the following requirements due to comments raised:

R1.5: A transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.
R1.6: An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running. The Operating Process shall include:
R1.6.1. A list of all entities to notify when there is a change in operating locations.
R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.
~~**R6.** Each Reliability Coordinator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than two hours.~~
~~**R7.** Each Balancing Authority and applicable Transmission Operator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than six hours.~~
~~**R8.** For each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations.~~
~~**R8.1.** For each applicable Transmission Operator, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the situational awareness and control of facilities with defined Interconnection Reliability Operating Limits (IROLs) beyond the two hour time period.~~
~~**R8.2.** For each Balancing Authority, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the calculation and control of its ACE beyond the two hour time period.~~

#4 – Commenter	Yes	No	Comment
Allegheny Power		x	The difference in the transition time frame for the RC compared to the TOP and BA would seem to indicate that the loss of the functions of the RC are deemed to be more critical to the reliability of the BES than the loss of the functions conducted by the TOP and BA. To the contrary, it is most likely that the RC functions are dependant on the data supplied from a TOP or BA. The loss of the TOP or BA primary facility could deprive the RC of critical information. A 2-hour transition time seems appropriate for all three entities.
American Transmission Company		x	Should be the same as requirement 6.
Hydro Québec/TransÉnergie		x	HQT believe that bullets 8.1 and 8.2 are not related to requirement 8, perhaps these should be relocated to requirement 7.

#4 – Commenter	Yes	No	Comment
			The SDT should clarify why the RC has a maximum delay of 2 hour with no leeway for longer time while the TOP and BA have a maximum delay of 6 hour with a process to have situational awareness if the delay is planned to be greater than 2 hour. HQT believe that the three entities should have the same time delay and leeway time. See our answer to Q3.
Manitoba Hydro Energy Board		x	The time frame is too long, a lot can happen in six hours including mother nature dropping a lightning storm on top of the entity, which can cause much greater problems to the entity than the limited control they have during a transition period. I would suggest a time period of two hours.
Northeast Utilities		x	2 hours maximum seems more appropriate.
Sacramento Municipal Utility Dist.		x	In the role of a BA or TOP, a 2 to 6-hour time frame is insufficient for required reliable operation of the BES, and should be no greater than 2-hours.
SPP ORWG		x	The transition plan should be a constant 2 hours for BAs and TOPS. This would then eliminate the need for R8.1 and R8.2.
Response: The SDT has changed requirement R.6 and moved it to R1.5 and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours.			
Baltimore Gas and Electric		x	If greater than 2 hours, only if their plan includes processes that will ensure the situational awareness and control of facilities. We are unclear as to how this can be accomplished without someone physically being at the backup control center within the initial 2 hour period.
MA Dept. of Public Utilities			Regardless of the timeframe between a primary control center going down and activation of the backup facility, having a plan in place to seamlessly operate the system is paramount. As stated in question 3, one hour should be used for the reliability coordinator instead of two hours.
NY State Dept. of Public Service		x	Regardless of the timeframe between a primary control center going down and activation of the backup facility, having a plan in place to seamlessly operate the system is paramount. As stated in question 3, one hour should be used for the reliability coordinator instead of two hours.
Bonneville Power Admin.		x	For quiet periods of operation, 2-6 hours is adequate. However for challenging times (peak loads, storms, loss of major generation, operating near IROL or SOL limits) 2 hours is insufficient. In 2003, a company did not have situational awareness visibility for 30-60 minutes with very adverse consequences. NERC, the SDT and NERC entities should consider these adverse situations

<table>
<tr><th>#4 – Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>occuring during loss of control center. Could recent disturbances this month be managed during the transition to their current backup control center?</td></tr>
<tr><td colspan="4">Response: The SDT added language to requirement R.1.6 that requires all entities to have a plan that manages risk to the BES during the 2 hour transition period. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:
The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
Realistic expectations for travel time in emergency conditions between the 2 centers.
2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers.
There is additional functionality required in this standard that wasn’t there before.
Organizational inertia in responding to the disaster.
Cost benefit versus relative risk.
R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.
It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.</td></tr>
<tr><td>Dominion Virginia Power
Dominion Resources
Entergy
SERC OC Standards Review Group
Southern Company Services, Inc
Southeastern RC</td><td></td><td>x</td><td>DVP believes R8.1 and R8.2 are not appropriate subrequirements of Requirement 8 since they pertain to required functionality in the transition period while R8 pertains to a requirement for a notification list. We also believes that all functional entities subject to this standard in its current form should have a two hour transition period. As currently written, R8.1 and R8.2 are essentially unmeasureable.</td></tr>
<tr><td>ISO New England</td><td></td><td>x</td><td>Bullets 8.1 and 8.2 appear to be related to requirement 7, not 8.</td></tr>
<tr><td>Madison Gas and Electric</td><td>x</td><td></td><td>Since R8.1 and R8.2 break down R7, they should be renumbered as sub bullets to R7.</td></tr>
<tr><td>NPCC Regional Standards Cmte.</td><td></td><td>x</td><td>NPCC participating members believe that bullets 8.1 and 8.2 are not related to requirement 8, perhaps these should be relocated to requirement 7.</td></tr>
<tr><td colspan="4">Response: Requirements R.8.1 and R.8.2 have been eliminated with the change to require TOP’s and BA’s to transition to their backup functionality with a two hour time period.</td></tr>
<tr><td>Duke Energy Corp.</td><td></td><td>x</td><td>6 hours is far too long to get backup functionality up and running. TOP's and</td></tr>
</table>

#4 – Commenter	Yes	No	Comment
			BA's should be on the same 2-hour clock as the Reliability Coordinator. TOPs and BAs have direct communications to field locations and personnel that are critical under normal and emergency conditions. Many RCs do not have this capability and depend on TOPs and BAs to provide this link to the capability on the ground. See response to Comment #3 above. While we believe 2 hours may be reasonable, R7 like R6 is an ambiguous requirement. It is unclear exactly what the transition period is referring to. It may not always be possible to establish an exactly precise point in time when primary control center functionality was lost. Likewise, it may not always be possible to define an exact point in time when backup functionality is "up and running". Furthermore, it is unclear whether this is just a requirement to have an appropriate plan, or whether it is a requirement to always meet the time limit, whether for tests or actual activation.
Response: The SDT has changed requirement R.6 and moved it to R1.5, and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours. The SDT believes that most of the backup functionality will be met by computer systems that should log events and times to a level that would allow a time-line to be created in hindsight. In the event of a catastrophic failure that destroys the computer systems, loss of connectivity to other systems could be used. Dashboard summaries of systems and alarms on the failure of systems should be included to allow operations personnel to determine the health of systems in real-time and detect failures that would require the use of backup functionality.			
Entergy – System Planning	x	x	It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. A statistical risk analysis would be ideal to determine this allowable time, if a valid model exists. If an arbitrary value is used, then an industry survey or something similar (experts/EPRI) may be appropriate.
Response: The SDT is not aware of available risk models for backup control center restoration analysis. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons: • The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it. • If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden. • Realistic expectations for travel time in emergency conditions between the 2 centers. • 2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers. • There is additional functionality required in this standard that wasn't there before.			

#4 – Commenter	Yes	No	Comment
• Organizational inertia in responding to the disaster. • Cost benefit versus relative risk. • R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability. • It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.			
FirstEnergy Corp.		x	We do not agree with the "6-hour" time frame. Also, we suggest allowing provisions if the transition time takes longer than 2 hours. Similar to the current requirement for transition time from EOP-008-0 Requirement R1.8, we suggest rewording R7 and R8 as follows [rewording also includes GOP with centralized dispatched control center based on our comments from Question #2]: R7: "Each Balancing Authority, Transmission Operator, and Generator Operator with a centrally dispatched control center shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is no more than one hour. Interim provisions must be included if it is less than two hours. Interim provisions must be included in the plan when extenuating circumstances cause the transition to take longer than two hours." For R8, we suggest rewording as follows: "For each Reliability Coordinator, Balancing Authority, Transmission Operator, and Generator Operator with a centrally dispatched control center, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations. R8.1 & R8.2 - We believe that these requirements are not necessary. Requirement R1.5 already includes requirements for the transition period while backup functionality is obtained. We suggest removing these requirements.
Response: The SDT has changed requirement R.6 and moved it to R1.5 and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours. See question #2 for comments on GOP's. The SDT added language to requirement R.1.6 that requires all entities to have a plan that manages risk to the BES during the 2 hour transition period.			
Hydro One Networks, Inc.	x	x	The timeframe for the TOP should depend on whether its RC has the capability to be in "operational control" within 2 hours. There is no point in the RC be up and running within the 2 hours frame if they cannot control the system (e.g. switch, breakers). If the TOP is the only entity with "operational control" of

#4 – Commenter	Yes	No	Comment
			Critial Assets or IROLs, then they must also be required to be up and running in the same timeframe as the RC. Requirement R8.1. touches on this concept however, we suggest the words are changed to provide for more clarity.
IESO		x	We do not understand the rationale behind the difference in the 2-hour time frame for the RC and the 6-hour time frame for the BA/TOP. Mosts RCs rely on the BAs and TOPs to implement actions to ensure reliable operation of its RC area. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant to meet its 2 hour. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC. Additionally, we urge the SDT to consider our suggestion made in Q3 that: ".. the requirement be written such that the responsible entity shall provide operational capability at all times to ensure continuous operation, monitoring and control of the BES.
ISO/RTO Council		x	Most RCs only have functional control of the transmission system. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC. In fact, we recommend an alternative approach to a time limit in question 3. We repeat that here and suggest it for application to the TOP and BA as well. In fact, we recommend that time frame should not be considered. The entity should be responsible for meeting a core set of requirements at all times.
Midwest ISO		x	Most RCs only have functional control of the transmission system. They will be helpless to have directives implemented if the TOP or BA does not have a functioning control center or alternate plan to perform actions such as switching in the field or dispatch at the plant. Thus, a six hour outage of a BA could in effect be equivalent to a six-hour outage of the RC. These times should match what is ultimately decided for the RC unless our alternative approach in our response to question three is adopted.

#4 – Commenter	Yes	No	Comment
			Our alternative approach presented in our comments in question three should apply here as well. It is included below. Rather than specify a time frame for transition, we suggest alternative approach that is more justifiable. This approach would require the responsible entity to have minimal capability to meet the core set of applicable requirements during the transition. The drafting team will need to identify those core set of requirements.
PJM Interconnection		x	RC's typically have a limited ability to control generation or transmission facilities. Without the BA and TOP control facilities, the RC will not be able to effectively perform its' functions. Therefore, the BA and TOP entities should be required to meet the same one hour time limit that applies to RCs.
Response: The SDT has changed requirement R.6 and moved it to R1.5 and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours. The SDT added language to requirement R.1.6 that requires all entities to have a plan that manages risk to the BES during the 2 hour transition period. Each entity will need to develop its individual plan to meet these requirements. The SDT did not feel that it was possible to provide greater detail for this plan given the many and varied circumstances of individual RC's, TOP's and BA's.			
Nebraska Public Power District		x	This standard addresses an event that probably will never happen for the vast majority of TO's and BA's. Shorter time frames require more elaborate and expensive systems (i.e. hot back-up versus cold back-up). The additional complexity isn't justified by the probability of having an event. Instead of two hours, the time to transition functions to the backup should be six hours. The backup should be fully functional within 24 hours after the event. An actual event, noted to be extremely rare to occur, will probably result in the loss of human life and infrastructure. The initial discovery and realization to implement the backup will be delayed by emergency response and the real-world crisis. Shorter response times could require 7 X 24 staffing at the Backup Facility. I'm not aware of a significant number of actual events that had demonstrated this need.
Response: The SDT attempted to weigh all of these issues in determining applicability and time frames for implementing backup capabilities. It is not the intent of the SDT to require all entities to provide "hot" backup capabilities.			
Santee Cooper	x		To have the backup plan implemented and backup functionality in operation in a two to three hour period is quite reasonable in our opinion. We do believe that it should be at least two hours but perhaps no more than three hours. Smaller

<table>
<tr><th>#4 – Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>entities that need a larger physical separation between control centers will need at least two hours. In most cases, three hours should be the limit.</td></tr>
<tr><td>Sierra Pacific Power Company</td><td></td><td>x</td><td>By allowing a six hour transition period,the standard basically is saying that a BA's ACE is unimportant for that time period. The old requirement of 1/2 hour should be maintained.</td></tr>
<tr><td colspan="4">Response: The SDT has changed requirement R.6 and moved it to R1.5 and deleted R.7, R.8, R.8.1, and R.8.2 such that TOP's and BA's must implement their backup functionality within 2 hours. The SDT added language to requirement R.1.6 that requires all entities to have a plan that manages risk to the BES during the 2 hour transition period.</td></tr>
<tr><td>Midwest Reliability Organization</td><td>x</td><td>x</td><td>The MRO would like to question why in this era of "hot" standby systems would it take an RC 6 hours to get their backup site operating? The MRO would like the SDT to share the methodology they used in determining these time periods.</td></tr>
<tr><td colspan="4">Response: Requirement R6 (now R1.5) requires backup functionality up and running in less than 2 hours. There can always be debate on the actual timeframe selected but the SDT believes that 2 hours is a reasonable timeframe for the following reasons:
The original standard only required implementation of the plan within 1 hour while this revision now requires actual operation of the backup within the 2 hour timeframe thus strengthening the standard and not weakening it.
If the time was any shorter it would drive the industry to implement a staffed, hot backup site resulting in an undue financial burden.
Realistic expectations for travel time in emergency conditions between the 2 centers.
2 hours gives RC management discretion for selecting sites that are sufficiently geographically separated to provide for increased reliability by reducing the risk of common events taking out both centers.
There is additional functionality required in this standard that wasn't there before.
Organizational inertia in responding to the disaster.
Cost benefit versus relative risk.
R1.6 now tightens the standard by requiring the plan to include operating actions prior to establishing full backup capability.
It is assumed that all of the Balancing Authorities and Transmission Operators under the RC continue to have their normal primary functionality available, which reduces the dependency of the stability of the BES on the RC.</td></tr>
<tr><td>Avista Corporation</td><td>x</td><td></td><td></td></tr>
<tr><td>Chelan County PUD</td><td>x</td><td></td><td>6 hours is a long time, however I know that some utilities have to travel long distances to their backup control center. It is difficult to imagine a scenario where we wouldn't be able to be up and running in less than 1 hour.</td></tr>
<tr><td>Comision Federal de Electricidad</td><td>x</td><td></td><td></td></tr>
<tr><td>DTE Energy</td><td>x</td><td></td><td></td></tr>
</table>

#4 – Commenter	Yes	No	Comment
Gainesville Regional Utilities	x		
Oncor Electric Delivery Company	x		
PacifiCorp	x		
Pacific Gas and Electric Company	x		
PS Commission of South Carolina	x		
Sierra Pacific Resources Transm.	x		I don't disagree with 6 hours for BA's and TOP's as a Requirement, although, I believe the industry entities can do much better tha
Tampa Electric Company	x		
WECC Operating Practices Subc.	x		
Xcel Energy	x		
Response: Thank you for your response. Please see the summary consideration – the drafting team modified the standard so that the backup plan for all responsible entities requires backup functionality up and running in less than 2 hours.			

5. Requirement R12 — Do you think that implementation or testing operations for a minimum of two hours annually is appropriate? If not, please state the reasons and suggest an alternative.

Summary Consideration: There was a wide range of comments regarding the 2 hours. Some suggested a longer period others, suggested it be deleted altogether. The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and Contingency evaluation, evacuation procedures & protocols, situational awareness tools, etc. Therefore the SDT feels that 2 hours is sufficient to test these basic functions. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e., voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs.

The other significant issue was in regards to integrating operator training into the test. The SDT decided operator training issues are best left with the PER standards, therefore these comments were not included though it does not preclude an entity from integrating operating training into the test.

Comments also identified that the requirement was not clear as to whether the 2 hours is continuous. The standard was revised to make clear the requirement is 2 continuous hours annually.

It should be noted that the intent of the standard is to verify the functionality of the Operating Plan through actual implementation, or through test operations, of the backup functionality for two continuous hours. It is not required that each operator be tested on these plans for two hours annually.

Others comments stated that Requirement R12 was more appropriate as a measure for Requirement R6. However, these are 2 distinct requirements, Requirement R6 (now R1.5) being the time to transition to the BCC and Requirement R12 (now R8) the test duration. Therefore these comments do not require a change to the standard.

Due to industry comments, Requirement R12 (R8 in the revised standard) was changed as follows:

~~R12.~~ R8. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall conduct an annual test of its Operating Plan that includes: ~~for backup functionality through actual implementation or test operations for a minimum of two continuous hours annually.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8.1 A demonstration of the transition time between the primary control center and the initiation of backup functionality.

R8.2 Actual implementation or test operations of the backup functionality for a minimum of two continuous hours.

R8.3 Test results shall be documented and lessons learned noted and incorporated in subsequent revisions of the Operating Plan for backup functionality.

#5 – Commenter	Yes	No	Comment
Allegheny Power		X	A 2 hour test would most likely not be long enough to test all the functions that

#5 – Commenter	Yes	No	Comment
			occur in a routine day. A minimum time requirement makes less sense than requiring that all functions required to be conducted during a normal day be tested.
Response: This is a test of the plan – not training. Training is left to PER. 2 hours allows one to go across an hour boundary and therefore to see schedules and ramps in action. If it takes up to 2 hours to transition to the backup site, then a 2 hour test will basically occupy a shift. This should be sufficient to show that the plan is 'real'. It represents a significant step up from the original standard. You can always do more.			
Baltimore Gas and Electric		x	The requirement should state that all operating personnel should operate real-time at the backup facility for a minimum of 1 shift per year in order to stay proficient with the transistion plan and the operations at the backup facility. This also provides more thourogh testing of the equipment at the backup facility when the center is utilized for real-time operations.
Sacramento Municipal Utility Dist.		x	To ensure familiarity with an entity's BCC, a minimum of two weeks (14 days) should be required to ensure all operator crews have the necessary experience.
Response: The SDT considered this but after deliberation decided this was best covered by the PER Standards regarding training.			
Bonneville Power Admin.		x	One specific change - "power sources" such as engine generators and UPS should be tested more often, weekly or monthly. In disturbances, control center EGs and UPS are often problematic. Also, if the backup software systems must be up to date as mentioned in R1.3 how does a BA or TO know without testing? Change the language to "adequately test all functions of the backup control center that are needed to replace the primary control center operation." For example: - test AGC for two hours annually, or when changes that impact operation - test voltage control for two hours. - test power sources EG/UPS monthly NERC CIP standards have requirements more frequent than annually that apply to backup control centers.
Response: Frequency of backup generators and UPS testing is developed considering many factors, most significantly vendor recommendations. Therefore, it would be imprudent for the standard to specify a testing frequency for backup power supplies. The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and contingency evaluation, evacuation procedures and protocols, situational awareness tools, etc. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e., voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs.			

#5 – Commenter	Yes	No	Comment
Dominion Virginia Power (1) Dominion Virginia Power (2) Entergy SERC OC Standards Review Group		x	DVP believes that R12 is more appropriate as a measure for R6, and the number of required hours to test the plan is immaterial to reliability.
Southern Company Services, Inc.	x	x	Southern Company: Southern believes that R12 is more appropriate as a measure for R6 and the number of required hours to test the plan is immaterial to reliability. There seems to be an emphasis on "two hours" here. The real empahsis should be on each applicable entity performing an adequate test of their backup facility. Southeastern RC comment: Agrees with this.
Response: R6 & 7 (now R1.5) define a transition times, R12 (now R8) defines testing durations. The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and contingency evaluation, evacuation procedures and protocols, situational awareness tools, etc. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e., voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs.			
Duke Energy Corp.		x	A single test of 2 hours duration annually is of very limited value for system operators and the backup functionality. This significantly limits the number of system operators who experience backup control, but more importantly minimizes the capability testing of the backup control functionality. This is a very low hurdle. This requirement is also silent on backup control functionality training. Specific training should be included in the training standards.
Entergy – System Planning	x	x	It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. Otherwise, the testing should be of adequate length to test the back up functions, whether it be 30 minutes or 12 hours would be dependent upon the entity's desires.
FirstEnergy Corp.		x	We agree with testing is very important. We also think that it is important enough that it should be performed more frequently and longer each time. We suggest a change from "two hours annually" to "four continuous hours semi-annually".
IESO ISO/RTO Council		x	There should be a mininum amount of testing required. However, we don't see a justification for two hours. We ask the SDT to provide a justification for this important time frame. In the absence of a technical justification, we recommend a full testing of an entity's backup plan be completed regardless of

#5 – Commenter	Yes	No	Comment
			the time required.
Madison Gas and Electric		x	There should be adequate testing of the backup facility. A two hour annual test could consist of four, 30 minute periods. R12 should be written that "... implementation or test operations to ensure the RC, TOP, BA's minimum requirements are met per R1". This would ensure that the Operating Plan was implemented and all sub bullets of R1 are tested or simulated. As a BA, we would want to see an entire hour (hour ending X to hour ending Y) of information. This would allow us to ensure that the Operating Plan of R1 is satisified.
Midwest ISO		x	There should be a mininum amount of testing required. However, we don't see a justification for two hours. Why not one or three? The SDT should establish a justification for this important time frame. It should not be arbitrary or based on judgment.
PJM Interconnection		x	The two hour requirement appears to be arbitrary and should not be included in the standard. The standard should state something to the effect that “Each Reliability Coordinator, Balancing Authority and Transmission Operator shall test its Operating Plan for backup functionality through actual implementation or test operations on a semi-annual basis.”
Response: The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and contingency evaluation, evacuation procedures and protocols, situational awareness tools, etc. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e., voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs. The SDT considered adding training requirements but decided this was best covered by the PER Standards regarding training.			
Gainesville Regional Utilities		x	I do believe that the BU facility, (If one has been established) should be tested annually by the operations personnel once a year. Not necessarily 2 hours a year.
Hydro One Networks, Inc.	x	x	Yes: 2 hours annually is appropriate. However please clarify if this requirement should read, "minimum of two CONTINUOUS hours, annually." Also, is there consideration in the variance of testing the Operating Plan with respect to weather conditions (e.g. summer conditions vs. winter conditions)? In some locations, weather conditions may have a significant impact on staff transportation time.
Xcel Energy	x		The provision should be revised to clarify whether the two-hour testing requirement is cumulative over the course of a year or whether the two-hour

#5 – Commenter	Yes	No	Comment
			test is to be achieved over the course of two consecutive hours.
Response: R12 (now R8) was changed to clarify the intent of the SDT. It now reads: ~~R12.~~ R8. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall conduct an annual test of its Operating Plan that includes: ~~for backup functionality through actual implementation or test operations for a minimum of two continuous hours annually.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]* R8.1 A demonstration of the transition time between the primary control center and the initiation of backup functionality. R8.2 Actual implementation or test operations of the backup functionality for a minimum of two continuous hours. R8.3 Test results shall be documented and lessons learned noted and incorporated in subsequent revisions of the Operating Plan for backup functionality.			
Manitoba Hydro Energy Board		x	I think the time frame should be left up to the entity, they just have to ensure the backup is tested thoroughly.
Santee Cooper		x	We believe that should be left to the individual company and their corporate procedures. If you require it, it could unnecessarily introduce reliability problems to the real-time system.
Response: The intent of the 2 hours was to test the basic functionality such as SCADA, alarm monitoring, voice & data communications, AGC, state estimator and contingency evaluation, evacuation procedures and protocols, situational awareness tools, etc. The 2 hours also allows enough time to operate through schedule changes over top of the hour. Testing all functions may not be practical since some functions are dependent upon system conditions (i.e. voltage reduction or load shedding would only be tested if needed). In addition entities may have different tools and different testing needs. The test can always be rescheduled or aborted should system conditions, weather, etc., present an unnecessary risk while testing the BCC.			
Midwest Reliability Organization	x	x	That depends on the conditions during the test. Operators may not be aware of specific issues with the back up control center if they only operate that location for two hour annually, plus, issues may emerge outside the 2 hour testing operational period;It's difficult to say what those issues may be at this time.
Response: The test can always be rescheduled or aborted should system conditions, weather, etc., present an unnecessary risk while testing the BCC. In addition it does not preclude taking precautions such as keeping the Primary Control Center staffed during the test.			
SPP ORWG		x	We would propose two hours quarterly.
Response: The objective is to ensure functionality. R1.3 requires a process to keep the BCC current with the Primary Control Center. Testing is meant to verify the functionality. Therefore it is not necessary to test more frequently.			
Pacific Gas and Electric Company	x	x	It is also unclear as to who will be testing it? Are the Operating Plans for the

#5 – Commenter	Yes	No	Comment
			functionality to be tested for the two hours annually, ment for each operator or is it only for that control center, once per year?
Response: The intent was a test whereby real time operations is being conducted at the BCC and therefore this would be done by operators.			
MA Dept. of Public Utilities			No comment.
NY State Dept. of Public Service			No comment.
American Transmission Company	x		The two hour testing is appropriate.
Chelan County PUD	x		
Comision Federal de Electricidad	x		If the assumption applies to the implementation or testing operations of the backup center and not each individual.
DTE Energy	x		
Hydro Québec/TransÉnergie	x		It is a minimum.
ISO New England	x		It is a minimum.
Nebraska Public Power District	x		
Northeast Utilities	x		Yes, as a minimum.
NPCC Regional Standards Cmte.	x		It is a minimumn
Oncor Electric Delivery Company	x		
PacifiCorp	x		
PS Commission of South Carolina	x		
Sierra Pacific Power Company	x		
Sierra Pacific Resources Transm.	x		This is a good idea. Having to operate through 1 or more hourly ramp periods is a reasonable test of functionality.
Tampa Electric Company	x		
WECC Operating Practices Subc.	x		If the assumption applies to the implementation or testing operations of the backup center and not each individual.

#5 – Commenter	Yes	No	Comment
Response: Thank you for your response. The testing relates to functionality – not to individuals. Please see the summary consideration – the drafting team modified the requirement to improve its clarity.			

6. Requirement R13 — The SDT proposes that within 6 calendar months of having lost its primary control center or backup capability that an entity will have a plan in place for re-establishing backup capability. Is 6 calendar months appropriate? If not, please state the reasons and suggest an alternative.

Summary Consideration: The drafting team received several responses to this question. They were very nearly evenly divided between those that agreed with the requirement and those that disagreed from the point of view that six months is too long to allow an entity to develop a plan for re-establishing backup capability. After much discussion, the SDT has decided to leave Requirement R13 as currently written, allowing 6 months for developing a plan to re-establish backup capability after a major event causes the primary or backup functionality to be degraded for the reasons detailed in the responses. Changes were made to Requirements R4 and R5 in an attempt to clarify when these requirements are in effect:

R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.

#6 – Commenter	Yes	No	Comment
Allegheny Power		x	The RC, TOP, or BA that losses it's primary or back-up control center should notify it's Regional Entity and neighboring entities within 24 hours. Within that 24 hour period, that entity should provide a plan that would outline how the loss of the remaining facility would be handled. There should always be a plan for the next contingency. A plan to re-establish a lost facility is less important that providing a plan to handle the loss of the remaining facility.

Response: The SDT agress that an entity that has lost its primary control center must contact its Regional Entity and re-establish communications with its RC and neighbors as soon as possible. The primary focus of an entity in this situation is ensuring that they are able to maintain visibility and control of its system, and that it has staff, equipment and logistics to ensure that its operation is sustainable.
The SDT is concerned that it may not be evident within the first 24 hours whether the total loss of the primary or backup capability will last for more than 6 months. The SDT's intent is not that the lost facility or functionality be replaced within a specific timeframe, but that backup capability be restored to ensure that reliable operation of the BES is maintained if the remaining control center or functionality is lost.

The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following:

- Need to recover from the actual incident.
- Continuity of operations could delay the planning process.

<table>
<tr><th>#6 – Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">

- Time is needed to evaluate the damage to the affected site.
- Development and evaluation of alternatives.
- Internal approval cycles.

</td></tr>
<tr><td>American Transmission Company</td><td></td><td>x</td><td>Six months is an excessive amount of time to have a plan for re-establishing backup capability. ATC belives that three months is a more appropriate amount of time.

Why does the SDT believe that six months is needed in order to develop a plan for re-establisting backup capability? ATC would say that establishing backup capability may take more than six months but to develop a plan should not take six months.</td></tr>
<tr><td>Chelan County PUD</td><td></td><td>x</td><td>6 months to develop a plan? No timeframe to have lost control facilities operational? Why have a requirement? Perhaps developing a plan in 3 months or less and demonstrating progress according to schedule to restore lost control functionality - or something like that.</td></tr>
<tr><td>Gainesville Regional Utilities</td><td></td><td>x</td><td>I believe this needs to be removed. because in the case of a primary facility being lost, everyone in the regiona including NERC and FERC will know the primary facility is lost. Remove requirement. Within 6 months a back up plan has been utilized during the time period.</td></tr>
<tr><td>Northeast Utilities</td><td></td><td>x</td><td>6 months seems excessive. It seems within 2 months an entity should at least have a plan.</td></tr>
<tr><td colspan="4">

Response: The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for their remaining control facility in the event of a loss of primary or backup control capability.

The SDT believes 6 month is a reasonable time period for the development of a plan because it allows for the following:

- Need to recover from the actual incident.
- Continuity of operations could delay the planning process.
- Time is needed to evaluate the damage to the affected site.
- Development and evaluation of alternatives.
- Internal approval cycles.

</td></tr>
<tr><td>Avista Corporation</td><td></td><td>x</td><td>Change to 12 calendar months for a plan. Need wording to indicate you are specifically exempt from EOP-008 for a time period (24-36 months) for rebuilding your control center.</td></tr>
<tr><td colspan="4">

Response: The SDT has added language to the Requirements R4 & R5 to clarify that the standard is not applicable after the loss of the primary facility and after the backup functionality is fully implemented, as that would impose an obligation for a tertiary site.

</td></tr>
</table>

#6 – Commenter	Yes	No	Comment
R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively. Depending upon the size and operational scope of entity, the SDT feels that 24 months to reestablish backup capability might be excessive. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Baltimore Gas and Electric		x	What does "have a plan in place for re-establishing backup capability" mean? Does this mean a) - that the requirement is to have a plan to establish backup capability or b) - is the requirement to re-establish backup functionality within 6 months? If a) is the intent, 6 months is too long to only develop a plan. A temporary backup solution should be required much sooner than 6 months. As written, R13 is not clear. Need to clarify R13 requirement. It is not clear that the RC, BA, and TO need to supply the backup plan 6 months PRIOR to the anticipated date that they expect the primary or backup control center to be inoperable. As stated, it could be supplied 6 months after the date that the functionality is lost.
Response: "Have a plan in place for re-establishing backup capability" means a) as referenced in the question. The SDT included Requirement R13 because we wanted to allow some period of time for an entity that has sustained the loss of its primary control facility, and such loss is expected to last more than six calendar months, to develop a reasonable plan to restore backup capability for its remaining control facility. It was not intended that the entity would have to have a replacement for its lost control center within 6 months. It was not intended that the entity would have to supply the backup plan 6 months prior to the loss of its primary backup center. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident.			

#6 – Commenter	Yes	No	Comment
• Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Dominion Virginia Power Dominion Resources Entergy SERC OC Standards Review Group		x	This requirement is construed as attempting to give an entity an automatic waiver from R1 through R12 of this standard, following a catastrophic loss of its primary or backup control center (BUCC) that is a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC?
Hydro Québec/TransÉnergie	x	x	HQT suggest the drafting team to provide for a compliance exemption should the primary or back up control center be lost because of a catastrophic failure.
NPCC Regional Standards Cmte.	x	x	NPCC participating members suggest the drafting team provide for a compliance exemption should the primary or back up control center be lost because of a catastrophic failure.
Southern Company Services, Inc.		x	Southern Company: This requirement can be interpreted as attempting to give an applicable entity an automatic waiver from R1 through R12 following a catastrophic loss of its primary or backup control center (BUCC) under a force majeure event. As written, it does not accomplish that goal. For example, what about the scenario where a primary control center is uninhabitable for longer than 2 hours? Is that entity immediately non compliant for this standard for having no backup for its BUCC? Southeastern RC comment: The answer is no, because the moment the primary center is lost, the RC, BA or TOP are out of Compliance. Thus to meet compliance, an entity would be required to have one primary and two backup centers. A lot of detail is lost in this requirement. It should state upon the loss of the primary center the RC, BA, or TOP are exempt from six (6) until a plan can be developed for an additional backup facility. The plan should include a backup center.

Response: The SDT has added language to the Requirements R4 & R5 to clarify that the standard is not applicable after the loss of the primary facility and after the backup functionality is fully implemented, as that would impose an obligation for a tertiary site.

R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance

#6 – Commenter	Yes	No	Comment
with all Reliability Standards applicable to the Reliability Coordinator. R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively. The SDT recognizes that in the event of a complete loss of a control center it may likely require an extensive amount of time to rebuild the control center. It is the intention of the SDT to require that in the unlikely event of a loss of primary or backup functionality that is anticipated to last for more than six months, the RC, TOP or BA provide plans within six months to show how it will re-establish backup capability.			
Entergy – System Planning		x	Recommend a shorter time time frame such as within 30 days, and updated every 30 days until back up capability is restored. 6 months is too long for an entity to not have a plan for continuing operations if its primary or back up facility are unavailable. The plan itself may take longer than 6 months to complete.
Response: The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for its remaining control facility in the event of a loss of primary or backup capability. The SDT agrees that implementation of the plan may take longer than 6 months to complete, depending upon the scope and required functionality for that entity, and for that reason we have not chosen to address how long the entity has to implement the plan. It is our intention that this level of detail will be left up to the Regional Entity. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Hydro One Networks, Inc.		x	6 months is too long. We recommend 3-4 months. As well, please re-word the requirement to provide clairification on whether the plan is needed after the fact (while operating from the back-up facility) or in the planning stages of the Operating Plan? We referring the use of the word "anticipate" in the requirement. The phrases "... anticipate total loss ... will last for more than six months..." and "... within six months of the date when the funcationality is lost.." seem to be in conflict.
Response: The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for its remaining control facility after a loss of primary or backup capability. The SDT intends the meaning of the requirement to be that for an entity that has lost its primary control capability, and expects that the loss will last in excess of six calendar months to			

#6 – Commenter	Yes	No	Comment
submit a plan to re-establish backup capability to its Regional Entity. This plan would need to be submitted within 6 calendar months. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
IESO		x	We do not see the need for this requirement. It implies that the responsible entity must establish a long-term or an N-2 contingency plan. Losing a primary control capability/facility for a period longer than several days is a rare event, if it has ever occurred before. The need for a long-term plan seems unnecessary. If the backup capability is lost, then the responsible entity would fail its primary requirement of providing the backup capability, unless it immediately re-establish such a capability by securing new facilities or arranging backup by another entity. The need to provide a plan (within 6 months) if the backup capability is lost also seems unnecessary. In essence, no time frame needs to be stipulated; just a requirement for the responsible entity to demonstrate the backup capability requirement can continue to be met if the loss of either the primary of backup capability/facility is assessed to be indefinite.
Response: It is not the intent of the SDT to require an N-2 contingency plan. To make this clearer, the SDT added language to the applicability section of the standard to indicate that the standard would not be applicable during the time period after the loss of the primary control center and after the backup functionality is fully implemented. That is, there is not a requirement for a tertiary backup facility. The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for their remaining control facility after a loss of primary or backup capability. The SDT believes 6 months is a reasonable time period for the development of a plan because it allows for the following: • Need to recover from the actual incident. • Continuity of operations could delay the planning process. • Time is needed to evaluate the damage to the affected site. • Development and evaluation of alternatives. • Internal approval cycles.			
Madison Gas and Electric		x	We do not "anticipate" the loss of our primary or backup capability. If a RC, TOP ,

#6 – Commenter	Yes	No	Comment
			or BA was without their primary control center for any length of time it would have an impact on their revenue generation and would place a burden on "whoever" was assisting them. I would think that the Regional Entity would be involved and the RC, TOP or BA would be working to get their primary control center up and running as soon as possible. FERC Order 693 does not state a 6 month time frame. R13 could state that the Regional Entity will be notified whenever the primary control center is non-functional except when the backup control center is being tested or training is taking place. The RE will have a plan fullfilling R1 requirements if the primary and backup facilities are non operatible.
Response: The requirement is not specifying that a TOP, BA, or RC "anticipate" the loss of primary or backup capability with all factors known (i.e., type of loss, extent of damage, time to rebuild, etc.) ahead of time. The requirement is specifying that a BA, TOP, or RC that has experienced a loss of primary or backup capability and anticipates at that time that it will take longer than 6 months to restore the lost capability, will provide a plan how it will re-establish backup capability. The SDT included Requirement R13 because we wanted to allow some period of time for an entity to develop a reasonable plan to restore backup capability for their remaining control facility after a loss of primary or backup capability.			
PacifiCorp		x	If the site for the backup facility must be completely reconstructed, it may not be feasible for it to be re-established within 6 calendar months. 6 months to a year would be more appropriate, allowing room to relocate and re-establish, if necessary.
Midwest Reliability Organization	x	x	Appropriateness depends on what is needed to show the re-establishment of backup capability. What if an action is contingenct upon restriants that may take awhile to process like a building permit or limiting weather conditions restricting the re-establishment process(es)?
Response: Requirement R13 is not intended to require that the backup capability be restored within 6 months, but rather that the entity that has experienced a total loss of its primary or backup capability develop a plan within six months showing how it will re-establish backup capability. The implementation of the plan may well take longer than 6 months, depending upon the size and operational scope of the entity.			
PJM Interconnection		x	The structure of the requirement is confusing. We suggest that it be re-written as "If the Primary or backup functionality is lost then each RC, TOP and BA shall provide a plan to its Regional Entity within six calendar months showing how it will re-establish backup capability."
Response: The intent of Requirement R13 is to require a plan to be submitted, if the primary or backup functionality is lost AND if the restoration of the functionality is expected to take more than 6 months. The SDT believes that the current wording conveys that intent.			
Sacramento Municipal Utility Dist.		x	2 years would be more appropriate to re-establish either a PCC or BCC.
Response: Requirement R13 is not intended to require that the backup capability be restored within 6 months, but rather that the entity that has			

#6 – Commenter	Yes	No	Comment
experienced a total loss of its primary or backup capability develop a plan within six months showing how it will re-establish backup capability. The implementation of the plan may well take longer than 6 months, depending upon the size and operational scope of the entity.			
Duke Energy Corp.	x	x	This requirement seems reasonable, but needs more clarity. If the view of this requirement is that backup capability must be re-established within 6 months of the loss of primary functionality, we question whether it can done, particularly in situations where the primary capability is totally destroyed. Furthermore, while an entity is in the backup facility, perhaps for 6 months or longer while the primary facility is being restored, there should be a clear exemption from having a "backup for the backup", since the need for such a facility would be a very low probability event. Similarly, if more than one entity plans to utilize the same backup facility they should not be found non-compliant when another entity is utilizing the facility. The SDT should provide more clarity and specificity around the exceptions from requirements in the standard for these types of situations.
Response: Requirement R13 is not intended to require that the backup capability be restored within 6 months, but rather that the entity that has experienced a total loss of its primary or backup capability develop a plan within six months showing how it will re-establish backup capability. The implementation of the plan may well take longer than 6 months, depending upon the size and operational scope of the entity. The SDT has attempted to address this by including language in Requirements R4 & R5 making it clear that the standard is not applicable after the loss of the primary control center and after the implementation of the backup functionality is complete. That is, there is not a requirement to have a tertiary facility or functionality. R4: Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.			
ISO New England ISO/RTO Council Manitoba Hydro Energy Board Midwest ISO	x	x	This requirement is trying to anticipate every conceivable situation that could occur. Standards should not be written to anticipate all possible situations. In reality, this is a business continuity issue and does not belong in the standard. Most professionals with business continuity responsibilities believe that the risk of losing your main control center for such an extended period is extremely low. Most likely an entity will only have to implement their back-up capability plan for a short period of time and will be able to re-occupy their main control center.

#6 – Commenter	Yes	No	Comment
			Additionally, there are simply too many variables involved in establishing new backup capability for an extended period of time. The ERO and REs should work closely with the affected entity to develop a plan to restore backup capability to address this unlikely situation.
Response: The SDT does not agree that the requirement is trying to anticipate every conceivable situation. The SDT agrees that the loss of primary or backup capability is a low probability event. However, NERC and FERC believe that the potential impact to the Bulk Electric System due to such an event is great. Requirement R13 is intended to address the risk to the BES in the unlikely occurrence of the loss of primary or backup capability that is anticipated to last six months or more.			
MA Dept. of Public Utilities			No comment.
NY State Dept. of Public Service			No comment.
Bonneville Power Admin.	x		Having a plan in place within six months is reasonable if this includes getting budget approval for replacement. Having it functional within six months may prove difficult. EMS vendors have said they can complete a project in about 12-18 months. NERC should suggest or require that the backup be functional again in a specific time period such as 18-24 months after failure of the primary control center.
Comision Federal de Electricidad	x		6 months is reasonable and makes its clear of the requirement that has not been available in the past.
DTE Energy	x		
FirstEnergy Corp.	x		
Nebraska Public Power District	x		As long as it's a plan for re-establishing backup capability and not the actual backup capablity restored in six months, this requirement is achievable.
Oncor Electric Delivery Company	x		
Pacific Gas and Electric Company	x		
PS Commission of South Carolina	x		
Santee Cooper	x		We believe that 6 months is reasonable for a plan. We do not believe it is reasonable to expect full recovery in 6 months.
Sierra Pacific Power Company	x		
Sierra Pacific Resources	x		

#6 – Commenter	Yes	No	Comment
Transm.			
SPP ORWG	x		
Tampa Electric Company	x		
WECC Operating Practices Subc.	x		6 months is reasonable and makes its clear of the requirement that has not been available in the past.
Xcel Energy	x		
Response: Thank you for your response. The intent is to have the plan in place within 6 months – not to implement the plan within 6 months. Please see the Summary Consideration – Changes were made to Requirements R4 and R5 in an attempt to clarify when these requirements are in effect.			

7. If you are aware of any regional variances that would be required as a result of this standard, or if you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement, please identify them here.

Summary Consideration: Due to comments raised to this question, the SDT changed applicability criteria to eliminate the references to Critical Assets and has changed the timeframes so that all applicable entities now have the same 2 hour requirement. In addition, changes were made to address the transition period requirements. Specific changes were:

4.1.2. Transmission Operator ~~with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits (IROLs)~~ operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Reliability Entity to be critical to the reliability of the Bulk Electric System (BES).
R1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running. The Operating Process shall include:
R1.6.1. A list of all entities that will be notify when there is a change in operating locations.
R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.
~~**R8.** For each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations.~~
~~**R8.1**. For each applicable Transmission Operator, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the situational awareness and control of facilities with defined Interconnection Reliability Operating Limits (IROLs) beyond the two hour time period.~~
~~**R8.2**. For each Balancing Authority, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the calculation and control of its ACE beyond the two hour time period.~~

#7 – Commenter	Yes	No	Comment
IESO		x	Provided that our suggestion in the second part of Q1 is adopted. Letting TOP to decide if this standard applies to them based on their own determination of their critical assets and/or IROLs seems to be a self-regulation process, which violates the legislation establishing a requirement for the ERO.
ISO/RTO Council Midwest ISO	x		Allowing a BA or TOP to in effect determine if the standard applies to them because they determine their critical assets and/or IROLs is equivalent to self-regulation which is clearly a violation of the legislation establishing a requirement for the ERO.
Response: The use of critical assets as a determination of applicability has been removed. TOP applicability is now determined by: Transmission Operator ~~with control of Facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits~~			

#7 – Commenter	Yes	No	Comment
~~(IROLs)~~ operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Reliability Entity to be critical to the reliability of the Bulk Electric System (BES).			
DTE Energy	x		Previously identified FERC Order 693.
Response: Without any details being specified, the SDT is unable to respond to these comments.			
Hydro Québec/TransÉnergie	x		
Madison Gas and Electric	x		R8.2 states that the Operating Procedure will ensure the calculation and control of ACE beyond the two hour time period. BAL-005-0, R6 states that if a BA is unable to calculate ACE for more than 30 minutes it shall notify its RC. Perhaps the wording of R8.2 should be the same as BAL-005-0, R6 so there is no confusion.
Response: Requirement R8.2 has been deleted and new wording has been added to R1.5.2 to address this situation: R1.5.2 now reads: Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.			
Allegheny Power		x	
American Transmission Company			No comment.
Avista Corporation		x	
Baltimore Gas and Electric		x	
Bonneville Power Admin.		x	I don't know of any regional variation. However, for some BAs & TOPs, operating Special Protection Schemes is a critical issue for reliablility of the Bulk Electric System that may require a robust control center and backup control center. Additional requirements may be needed for managing SPS during all adverse power system conditions including loss of control center.
Chelan County PUD		x	
Comision Federal de Electricidad		x	Not aware of any at this time.
Dominion Virginia Power		x	
Dominion Resources		x	
Duke Energy Corp.		x	
Entergy – System Planning		x	

#7 – Commenter	Yes	No	Comment
Entergy		x	
FirstEnergy Corp.		x	
Gainesville Regional Utilities		x	
Hydro One Networks, Inc.			No comment.
ISO New England		x	
Manitoba Hydro Energy Board			No comment.
MA Dept. of Public Utilities			No comment.
Midwest Reliability Organization		x	N/A
Nebraska Public Power District		x	
NY State Dept. of Public Service			No comment.
Northeast Utilities		x	
NPCC Regional Standards Cmte.		x	
Oncor Electric Delivery Company			No comment.
PacifiCorp		x	
Pacific Gas and Electric Company		x	
PJM Interconnection		x	
PS Commission of South Carolina		x	
Sacramento Municipal Utility Dist.		x	Not aware of any at this time.
Santee Cooper		x	
SERC OC Standards Review Group		x	
Sierra Pacific Power Company			No comment.

#7 – Commenter	Yes	No	Comment
Sierra Pacific Resources Transm.		x	Not aware of any.
Southern Company Services, Inc.		x	
SPP ORWG		x	
Tampa Electric Company		x	
WECC Operating Practices Subc.		x	Not aware of any at this time.
Xcel Energy		x	
Response: Thank you for your response.			

8. If you have any other comments on the proposed standard that you haven't already provided in response to the questions above, please provide them here.

Summary Consideration: Numerous changes were made to the requirements as a result of the comments to this question. Specific changes included:

R1.1. The location and method of implementation for providing backup functionality for a prolonged period of time.
R1.2. An ~~high level~~ overview of the elements required to support the backup functionality.
R1.3. An Operating Process for keeping the backup functionality ~~current~~ consistent with the primary control center.
R1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. ~~including at a minimum:~~
R1.4.1. ~~Criteria for evacuation of the primary control center including the decision authority for initiating the Operating Plan for backup functionality and the Operating Process for initiation of backup functionality.~~
~~**R1.4.2.** Criteria for returning operations support to the primary control center including the decision authority and the Operating Process for returning to the primary control center.~~
R1.7. Identification of the roles for ~~all involved~~ personnel involved during the initiation and implementation of the Operating Plan for backup functionality ~~and for the return to the primary control center~~.

R4**:** Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.
R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.
~~**R7**. Each Balancing Authority and applicable Transmission Operator shall plan for a transition period (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) that is less than six hours.~~
~~**R8.** For each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations.~~
~~**R8.1**. For each applicable Transmission Operator, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the situational awareness and control of facilities with defined Interconnection Reliability Operating Limits (IROLs) beyond the two hour time period.~~
~~**R8.2**. For each Balancing Authority, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the calculation and control of its ACE beyond the two hour time period.~~
~~**R9**.~~ **R6.** Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~.
~~**R9.1**.~~ **R6.1** The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~ contact information.

~~R10.~~ **R7.** Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards.
R11. ~~Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that is capable of operating for an indefinite period of time.~~

#8 – Commenter	Yes	No	Comment
American Transmission Company	x		The standard introduces three new capitalized terms that are not defined in the Standard: Operating Plan, Operating Process and Operating Procedure. ATC does not agree with the creation of the three new terms and believes that the terms should be replaced with a more general statement; i.e. "plan, process or procedure" as follows: R1: Each RC, BA and TOP shall have a plan, process or procedure describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This plan, process or procedure for backup functionality shall include the following: R1.3 The plan, process or procedure shall document how the entity will maintain backup functionality current with the primary control center. R1.4 The plan, process or procedure shall document how the decision for implementation is to be made:
Response: Operating Plan, Operating Process, and Operating Procedure are all defined terms in the currently approved NERC Glossary. Therefore, no changes were made by the SDT.			
Avista Corporation	x		R8 requires further clarification. R9 - Requirement 9 should be moved under Requirement 1. The relation between the annual review and approval and the 60-day update and approval is not clear. R9.1 clarify to indicate "changes that effect the operating plan." R10 remove - basically a restatement of R4. Additionally "...any aspect of the

#8 – Commenter	Yes	No	Comment
			operation." encompases aspects that would not be related to the reliability of the system but would ba an aspect of the operation (i.e. filling out time sheets). R11 - remove - This requirement seems to be in conflict with the purpose of R1 and R13. R13- Recommed that this be changed to 1 year. If this actually happened, there will be other issues to consider which may be very complex and trying to make this decision in 6 months may apply undue pressure on the decision. We recommend exemption from EOP-008 until the completion of a plan to reestablish backup capability.
Response: R8 has been deleted. A portion of the requirement has been rewritten and moved to R1.5.1. R1 deals with what the plan should include whereas R9 (now R6) deals with the timeframes for review: i) annually no matter what and ii) within 60 days for major changes. There is no relationship between the 1 year and 60 day reviews. R9.1 – To say 'changes that affect the operating plan' is too general. The SDT has been more specific in order to identify significant changes (i.e., back-up location, capabilities, or communications protocols). The SDT has changed the wording in R9.1 (now R6.1) from 'communication protocol' to 'contact information' and it now reads: The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~ contact information. R10 (now R7) deals with RC, BA, & TOPs while R4 is specific to the RC. The SDT has changed the wording in R10 to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. R11 – This requirement has been moved to R1.1 and reads "for a prolonged period of time" rather than "an indefinite period of time." R1.1 now reads: "The location and method of implementation for providing backup functionality for a prolonged period of time." R13 – The requirement (now R9) is to provide a plan within the 6 month timeframe. There is always a dilemma when it comes to timeframes and the SDT determined that 6 months would be a reasonable timeframe to submit a plan. One must remember that the 6 months is not to have a backup center up and running but to submit the plan.			
Baltimore Gas and Electric	x		R1.6 identification of roles for ALL involved personnel may be too prescriptive. Thinking of all the scenarios for a loss of control center, certain individuals may be playing different roles. We think it should say, "all operations personnel" rather than "all involved" to limit the scope of pre-defined roles so that individuals such as support personnel can be used to the maximum effectiveness. As written, R3 is not clear. Need to clarify the R3 requirement. It is not clear how the standard applies to those other entities that perform the BES Operations.

#8 – Commenter	Yes	No	Comment
Response: R1.7: The plan calls for the identification of the personnel that will be involved with backup. The SDT has changed the wording of R1.7: Identification of the roles for ~~all involved~~ personnel involved during the initiation and implementation of the Operating Plan for backup functionality ~~and for the return to the primary control center~~. R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.			
Bonneville Power Admin.	x		This is a good improvement for EOP-008. if a BA or TOP has a "hot" back up site that is staffed 24/7, less prescribed testing or documentation is needed. R1.3 - add a timeline to keep current, weekly or monthly. Daily would be to difficult. R5 - "includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to BA & TO" . ALL Reliability Standards is too broad. An extreme example: Do we need monitoring of vegetation management at the backup control center? No. BAL standards for BAs - Yes. Prepare a list of standards/requirements we must meet from the B/U site. R10 language "backup capability that does not depend on the primary control center for any aspect of its operation" may force companies to buy a development system for the backup site. An EMS vendor may be able to provide development system on a temporary basis. Change "any aspect of its real time operation" R13 - Add a specific schedule for completion of backup control center functionality in addition to a plan. 2 years is reasonable. Will utilities still be liable for sanctions and penalities during loss of control center incidents and especially the 2-6 hour transition? Please have NERC comment. This may change the business case for backup control center.
Response: The fact that a TOP or BA has a hot backup does not preclude them from complying with this standard. R1.3: The SDT feels that it would be difficult to prescribe a time for updates because of the need to update various types of data that require			

#8 – Commenter	Yes	No	Comment
different backup times. The backup must have all the data necessary for operations to resume within the times specified in this standard. Therefore, the SDT does not feel the need to add a timeline to R1.3. However, the SDT has made a slight change to R1.3 for clarity: An Operating Process for keeping the backup functionality ~~current~~ consistent with the primary control center. R5: Although at first glance it might seem that Reliability Standards could be easily categorized as either directly affecting system reliability or of secondary importance, the SDT determined after much discussion that it was not practical. Items that at first appear not to directly affect reliability might in fact have a significant impact depending on the duration that that backup operation is in effect. As an example, the blackout of 2003 was caused by a combination of issues related to pure "real time operating requirements" as well as the vegetation management issue that has been suggested is secondary. Since we need to contemplate extended operation under a backup configuration, the SDT concluded that it was inappropriate to exempt any standard. R10 (now R7): The SDT has removed the 'any aspect of its operation' and changed the wording to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. R13 (now R9): The SDT wanted to stay away from specific completion timeframes and rather specify reasonable timeframes (6 months) for the formulation of a plan with its regional entity. Will utilities still be liable? - The SDT is attempting to address this issue to the best of their ability within their scope with the revised EOP-008. Requirements R7 and R8 have been removed from the Standard and all RC's, BA's & TOPs will have the same 2 hour requirement to establish reliable operations. In addition, the drafting team modified the applicability of the standard to clarify that during the two hour transition period, entities are not required to be compliant with the requirements in the standard.			
Chelan County PUD	x		We suggest the following for R10: Replace "for any aspect of its operation" with "any functionality required to maintain compliance with all applicable reliability standards".
Response: R10 (now R7): The SDT has removed the 'any aspect of its operation' and changed the wording to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards.			
Dominion Virginia Power Dominion Resources Entergy SERC OC Standards Review Group	x		1) There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the definition of what starts the transition period and what ends the transition period to the backup control center should be included in the standard. 2) Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure? 3) Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up. 4) A general comment is that this standard, taken as a whole, appears to include

#8 – Commenter	Yes	No	Comment
			"how" language. Requirements should be limited to "what" is required. Much of what is included in this standard appears to be "good utility practice" and not reliability requirements and should be stripped from the standard.
Response: 1) Measures have been developed for the second posting. The transition period is the time between loss of functionality and the restoration of functionality at the backup center. R7 has been deleted and the requirement is now the same for all applicable entities. 2) R11 has been moved to R1.1: The location and method of implementation for providing backup functionality for a prolonged period of time. 3) R4 and 5: Although at first glance it might seem that Reliability Standards could be easily categorized as either directly affecting system reliability or of secondary importance, the SDT determined after much discussion that it was not practical. Items that at first appear not to directly affect reliability might in fact have a significant impact depending on the duration that that backup operation is in effect. As an example the blackout of 2003 was caused by a combination of issues related to pure "real time operating requirements" as well as the vegetation management issue that has been suggested is secondary. Since we need to contemplate extended operation under a backup configuration, the SDT concluded that it was inappropriate to exempt any standard. 4) The SDT believes it has addressed the 'what' and has not drifted into 'how'. How entities address the requirements hasn't been mentioned.			
Southern Company Services, Inc.	x		Southern Company: There are no measures for the above requirements - therefore it is difficult to evaluate the impacts of their applicability. For example, the definition of what starts the transition period and what ends the transition period to the backup control center should be made more clear in the standard. Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure? Regarding R4 and R5 - Not all requirements are created equal - some real-time operating requirements are essential to be backed up. Southern Company EMS Services: We have concerns where an entity's current EMS system would not be compliant with the proposed standard, there should be adequate lead time for entities to make changes to their infrastructure to become compliant. Therefore, we would recommend an implementation plan to be a minimum of 2-3 years for this to occur. How does this standard address computer infrastructure which can be geographically separate from the control centers and backup facilities? If and when an event occurs, and one of the redundant sites is lost, what is the impact to compliance?
Response: Measures have been developed for the second posting. The transition period is the time between loss of functionality and the restoration of functionality at the backup center. R11 has been moved to R1.1: The location and method of implementation for providing backup functionality for a prolonged period of time. The Implementation Plan has been submitted with the second posting and provides a minimum of 2 years to become compliant from the time the standard is approved by applicable regulatory authorities.			

#8 – Commenter	Yes	No	Comment
This standard stresses functionality regardless of where equipment is located. Compliance is not within the scope of the SDT – it is an auditing function.			
DTE Energy	x		We would recommend that language for annual training for the operating personnel be included in the standard with a walkthrough and start up of the facility being the minimum. We feel the six calendar month language in R13 is to long of a time period.
Response: The SDT feels that the requirement for this standard is the operation of the back-up facility for 2 hours per year as per R12 (now R8). Training is the responsibility of the entity and is covered under another standard (Standard PER-002). R13 (now R9) – One must remember that 6 months is the time to submit a plan and not to have a backup center (or primary) fully functional. The SDT wanted to stay away from specific completion timeframes and rather specify reasonable timeframes (6 months) for the formulation of a plan with its regional entity.			
Duke Energy Corp.	x		The Purpose statement of this standard focuses on an event in which a control center becomes inoperable. Requirements then focus on providing "backup functionality" for a loss of primary control center functionality. The focus of the standard should be tightened up so that it is clear that entities are required to provide backup functionality that addresses loss of primary control center functionality. R10 requires that backup capability cannot depend on the primary control center for any aspect of its operation. This standard should more specific regarding how far "out" into the communications network infrastructure entities must assume the primary facility functionality reaches, for the purpose of establishing backup functionality. R11 states that the backup capability must be capable of operating for an indefinite period of time. It's unclear how compliance will be determined for this requirement.
Response: The purpose statement does identify loss of Control Center Functionality and the requirements focus on 'backup functionality'. There is only one requirement that directly identifies the primary facility capability and that is R13 (now R9). R10 (now R7) – It is not up to the SDT to be that specific. The primary and backup facilities need to be independent. R11 – Compliance elements have been submitted with the second posting. Note that the statement, "must be capable of operating for an indefinite period of time" was removed and is not in the revised standard.			
Entergy – System Planning	x		Consider adding provisions for short term planned and unplanned outages on either the primary or back up control center. This would be similar to outage

#8 – Commenter	Yes	No	Comment
			"time clocks" in the nuclear world. This would allow entities to make repairs, upgrades on the primary and back up control centers without automatically being non-compliant when conducting such activities. An example might be that the primary or back up control center not be unavailable (definition needed?) for more than 7 cumulative days per quarter. Exceptions may be granted by the Regional Compliance Enforcement Authority.

Response: See the revised R4 and R5.

R4**:** Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.

#8 – Commenter	Yes	No	Comment
FirstEnergy Corp.	x		1. Operating Plan, Operating Process, Operating Procedure - Some entities may use a combination of these documents or simply specific procedures or "steps" to ensure reliable backup functionality. The specific use of a Plan, Procedure, or Process may put additional burden on an entity to maintain additional and unnecessary documentation. Also, the use of all these terms make the wording awkward and degrade the readability of the standard. Therefore we suggest that anywhere an Operating Plan, Process or Procedure is required in this standard, that it simply states either a "plan" (note: small caps] or "steps required" that an entity be required to adhere to. If the SDT is bound to the use of the capitalized NERC terms, then, for flexibility, we suggest that anywhere an Operating Plan is required, that entities be allowed to provide an Operating Process or Operating Procedure as an alternative. Also, we suggest that anywhere an Operating Process is required, that an entity be allowed to provide an Operating Procedure as an alternative. We suggest an across the standard change from: a. "Operating Plan" to "Operating Plan, Operating Process, or Operating Procedure". [As an example of a precedent to using all three terms, see standard IRO-014-1 Requirement 1]

#8 – Commenter	Yes	No	Comment
			b: "Operating Process" to "Operating Process or Operating Procedure" 2. R1.2 - Suggest removing the phrase "high level" which is subjective. Providing simply an "overview" of the elements is a sufficient description. 3. R1.4.1 - This requirement is very confusing as written. To the point of the use of the terms Operating Plan, Process, and Procedure from our comment #1 above, this requirement needs to be simplified. We suggest rewording to simply: "Criteria for evacuation of the primary control center including the decision authority for initiating the plan or steps required for backup functionality." 4. R1.4.2 - Suggest removing the term "support". The goal of this requirement is to return to full operations, not just operations support. 5. R1.5 - The need to return back to the primary control center is missing from this requirement. Suggest adding the following at the end of this requirement: "as well as the actions to be taken to return back to primary control center functionality." 6. R1.6 - As written, this requirement could be too strict and not allow for personnel flexibility. Suggest rewording the requirement as follows: "Identification of the required roles of involved personnel during the initiation and implementation of the plan or steps required for backup functionality and for the return to the primary control center." 7. R2 - This requirement could be confusing as written and additionally seems to be missing important information regarding the operating and monitoring of the system during the transitional period. Suggest rewording this requirement as follows: "Each Reliability Coordinator, Balancing Authority, Transmission Operator and Generator Operator with a centrally dispatched control center shall have a copy of its plan or steps required for backup functionality located in its primary control center and at the location fulfilling backup functionality, and any facility used for operating or monitoring the BES during the transition process." 8. R3 - We believe that this requirement is duplicative of Requirement R1. The applicability and any delegation of TOP tasks would already be covered by R1. Therefore we suggest removing Requirement R3.

#8 – Commenter	Yes	No	Comment
			9. R4 - Standards must be followed and adhered to at all times. Therefore the last phrase of this requirement: "... as required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator" is unnecessary and should be removed. 10. R5 - Standards must be followed and adhered to at all times. Therefore the last phrase of this requirement: "... sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively" is unnecessary and should be removed. 11. R9 - To be consistent with other reliability standards, and to allow the entity flexibility in defining roles of authority over Operating Plans, Processes, and Procedures, we suggest removing the last phrase "... by a manager" 12. R9.1 - Since backup functionality includes more elements than just "location, capabilities, and communication protocols", we suggest simplifying this requirement and simply ending the sentence after "... of any changes." 13. R10 - The phrase "any aspect of" should be removed from this requirement. It is not clear what this means and not necessary. 14. R11 - We believe this requirement could be worded better as follows: Each Reliability Coordinator, Balancing Authority, Transmission Operator and Generator Operator with a centrally dispatched control center shall have backup capability to operate for an indefinite period of time."

Response: 1) Operating Plan, Operating Process, and Operating Procedure are all defined terms in the currently approved NERC Glossary and were used based on those respective definitions. Therefore, no changes were made by the SDT.

2) The SDT changed to wording of R1.2 to**:** An ~~high level~~ overview of the elements required to support the backup functionality.

3) The SDT has removed R1.4.1 and re-worded R1.4: Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. ~~including at a minimum:~~

4) The SDT has deleted R1.4.2.

5) The SDT has removed references for returning to the primary facility.

6) The plan needs to identify the personnel that will be involved with the backup. These may include operating, support, and management personnel. The wording of R1.7 has been changed to: Identification of the roles for ~~all involved~~ personnel involved during the initiation and implementation of the Operating Plan for backup functionality ~~and for the return to the primary control center.~~

#8 – Commenter	Yes	No	Comment
7) The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, the proposed change was not made to R2. 8) R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality. 9) R4 and 5: The purpose of R4 and R5 is to make it clear that the plan must include whatever is required to comply with all reliability standards. The SDT received comments implying that standards be categorized and that compliance to only some standards be required in a backup configuration. That reinforces the SDT's original decision to make it clear that adherence to all applicable standards is required in backup configuration. 10) Operating Plan, Operating Process, and Operating Procedure are all defined terms in the currently approved NERC Glossary and were used based on those respective definitions. Therefore, no changes were made by the SDT. 11) By a Manager has been removed from the requirement. The revised document will state under the new R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. 12) Saying "of any change" could imply anything. "Backup location, capabilities or communications" is more specific to changes in significant functionality. 13) R10 (now R7) deals with RC, BA, & TOPs while R4 is specific to the RC. The SDT has changed the wording in R10 (now R7) to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. R11 has been moved to R1.1: The location and method of implementation for providing backup functionality for a prolonged period of time.			
Gainesville Regional Utilities	x		R1.4.1 This does not need to be addressed, Any Operational entity in NERC can recognize a reason to abandon their primary Control Center.(Fire, Avalanche, Forest fire, Flood, Tornado, No building, No Computer, GLeaking Gas, etc.) I believe this is not necessary at all R1.4.2 Same reason, when all in normal , we return to the primary facility. R.2 What is the reason to have the Operating plan at both places. Each operator ahs theoretically been trained yearly on the plan and should have an understanding of what is required. What more is needed? The entire SAR needs to addressed. What is required is a plan to continue operation in the case of a primary Control Center, How it is accomplished seems up for more discussion as towhat may be required for continued operation. This SAR as others viseems to view all entities that hav decided to have a back up center rather than a plan meet requirements that are no necessarily needed.
Response: The SDT has removed R1.4.1 and re-worded R1.4: Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. ~~including at a minimum:~~ The SDT has deleted R1.4.2.			

#8 – Commenter	Yes	No	Comment
The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, the proposed change was not made to R2.			
Hydro One Networks, Inc.	x		Requirement R9 states that the Plan must be approved by a manager. Manager of what? This level of approval for such an important plan is too low. We suggest VP or higher. For review, we suggest an applicable "Operating/Control Room Manager".
Response: By a Manager has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. ~~reviewed and approved annually by a manager.~~			
Hydro Québec/TransÉnergie NPCC Regional Standards Cmte.	x		Drafting team should clarify the term "GOP centrally dispatched". The Drafting Team should focus on the reliability objective as opposed to how the objective is met.
ISO New England	x		The Drafting Team should focus on the reliability objective as opposed to how the objective is met.
Response: The GOP has not been included as an applicable entity in this Standard. "GOP centrally dispatched" refers to those GOPs that dispatch many dispersed plants from a central control center. FERC had in mind plants located across North America in multiple control areas. The SDT believes it has addressed the 'what' as opposed to the 'how'. The SDF has left it up to the entities to address how the requirements are implemented.			
IESO	x		R1 is written with the backup facility in mind. It needs revision if the backup plan is to a backup capability such as by transferring operational control to another operating entity. R2 - Adresses that the RC, BA and TOP shall have a copy of its operating plan to be physically located at both, the primary control facility and the back-up control facility. It does not address the issue of exchanging this information between the applicable entities. It is essential that the RC is aware of the TOP and BA's operating plans and backup centers - something akin to the system restoration plan - not sure if the RC should review and approve the backup operating plans of the the TOP and BA, but as a minimum, the RC should be provided with the appropriate information by the applicable TOP and BA entities. R3: It is unclear to us what this requirement aims to accomplish. If a responsible entity has to use other entities to implement its backup functionality, it will be explicitly included in its plan. R4 should be modified to require each RC to have an arrangement for backup

#8 – Commenter	Yes	No	Comment
			control facility or capability. This requirement will then be more succinct, as stringent, and provide the RC flexibility to make necessary business arrangements to provide backup capability. There is nothing especially important about the RC having its own backup control center or utilizing another RC's control center. It is possible that a third party might be willing to develop control capability to serve as a backup for multiple parties. R5 is really redundant to R1. If a BA and TOP must have a plan to have backup functionality, they have met Requirement 5. R9: We do not see the need to specify who in the responsible entity's organization should approve the plan (ref. approved by a manager). This is an internal business process that has nothing to do with reliability. If approval of a backup plan is required, then the responsible entities shall submit their plans to the RE for review and approval. The version 2 SAR of the subject matter references transmission owners (TOs) with transmission control centers as an applicable entity to this standard. The current draft of the standard is silent on such the applicability of TOs - was the omission deliberate? If it was, we do not see any statement or logic to this effect.

Response: R1 – The SDT does not feel that the requirement restricts moving control to another operating entity for backup. The only prescriptive requirement for backup is that the RC must have a backup facility but that the TOP and BA must have backup capability. Backup capability can be achieved by a backup facility or by contracted backup through another entity.

The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, no change was made to R2.

R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.

R4: The distinction between backup capabilities for RCs as compare to other entities arose from the FERC rulemaking relevant to this standard. FERC was emphatic that RCs have physical backup control centers. The SDT agrees that the emphasis should be on "what" as opposed to "how", and has changed the wording of the requirement to provide additional flexibility for RCs, but is constrained by FERC's direction on this point. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

#8 – Commenter	Yes	No	Comment
R5: Having both R1 and R5 is a key element of the modification of EOP-008. One of the main criticisms of EOP-008 was that it only required a plan, and did not sufficiently require that the plan be realistic, effective, and tested. The presence of R5 is to make clear that to merely have a plan is not sufficient. You must be able to demonstrate that you have the capability to maintain system reliability in your backup configuration. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. The SDT does not believe that the TO needs to be included in this standard. Focus is on the TOP and not the TO. Inclusion in a SAR is not mandatory for inclusion in the standard.			
ISO/RTO Council Midwest ISO	x		In general, this requirement is overly detailed and broad. There are really only three basic requirements for establishing backup operational capability. Those three requirements are: 1. Have a plan 2. Test plan 3. Implement when needed. Any requirements beyond these three basic requirements will only detract from reliability because they will cause entities to focus on requirements outside of these basics. Many of the subrequirements in this standard are not requirements at all. Rather they are criteria or lead-in statements for other subrequirements. This is problematic because the FERC has established VRFs for subrequirements in the past that are really not requirements and is now requiring the establishment of VSLs for many subrequirements that are not requirements at all or may even be explanatory text. This draft standard is perpetuating this problem. Any subrequirements that are criteria should simply be listed as bullets under the requirement with the requirement specifying that it is subject to the following criteria. For instance, all subrequirements under R1 do not really have any requirement. They are simply a list of what should be included in the plan identified in R1 or explanatory text. Thus, many of these sub-requirements should simply become bullets. This would also aid in the establishment of multiple VSLs because an entity that has a plan but is only missing couple of the requirements might have a low VSL. Whereas an entity, not having a plan would then fall into the SEVERE VSL. R1.1 is not necessary but is simply a part of a plan. A plan doesn't exist if it doesn't identify where and how. This could be specified as a criterion for the

#8 – Commenter	Yes	No	Comment
			plan. R1.2 is unneccesary. First, high level is subjective. Requirements should not be subjective. Secondly, each of the sub-requirements under it will stand alone without R1.2. R1.3 should be modified. What it really needs to state is that the backup functionality needs to have current BES data. It should not be tied to what the primary control center has because the primay control center data may be out of synch with the BES. This would be a reason to utilize the backup functionality. R1.4 is not necessary. The subrequirements under it do an adequate job of spelling out the basic minumum requirements without the introductory statement that R1.4 is. A third criteria should be added that identifies who makes the decision to implement the back-up plan. R2 is not necessary if there is going to be timing requirements for bringing the backup functionality. It is a good idea but should not be a requirement. In effect, requiring the backup functionality to be functioning in x amount of time will cause the responsible entity to have the plan at their fingertips. Additionally, a properly trained system operator should be able to implement the plan without referring to the plan. R3 is a requirement that is an example of an attempt to write the standard for a every conceivable sitiuation and is not necessary. If a responsible entity has to use other entities to implement its backup functionality, it will be explicitly included or they will not have a plan that they can test. Thus, they will not meet requirement. R4 should be modified to require each RC to have arranged for the availability of back-up capability. This requirement will then be more succinct, as stringent, and provide the RC flexibility to make necessary business arrangements to provide back-up capability. There is nothing especially important about the RC owning its own backup control center or utilizing another RC's control center. It is possible that a third party that is not an RC might be willing to develop a control center to serve as a backup for multiple parties. As long as the requirement functionality is provided, why would this be a problem? The

#8 – Commenter	Yes	No	Comment
			requirement as written would preclude this satisfactory arrangement. R5 is really redundant to R1. If a BA and TOP must have a plan to have backup functionality, they have met Requirement 5. Let's not create an opportunity for double jeopardy. Requirement 8 and all of its subrequirements are not really requirements. It really is criteria for R1. Requirement 9 should remove the requirement to have the plan approved by a manager. This is really a business process requirement and does nothing to ensure reliability. Besides, Requirement 13 will cause this to happen anyway. Do you really think that the plan can be tested annually without a manager's approval? R10 and R11 is not really a requirement. It belongs as a criterion under R1.

Response: General – a) The SDT feels that those elements have been addressed but that the details provided will permit more consistency in applying the standards. b) The organization of the requirements was reviewed by the SDT. However, the use of bullets will be dictated by NERC format rules.

R1.1: Since the method of implementation is part of the Plan, the SDT feels it must be listed as a requirement.

R1.2: The SDT changed to wording of R1.2 to**:** An ~~high level~~ overview of the elements required to support the backup functionality.

R1.3: The SDT agrees that if the primary system is out of synch with the BES that that may be a reason for moving operations support to the backup. The SDT does not feel that the standard should be prescriptive to the point of detailing what the reasons are for leaving a primary control center. That should be detailed in each entity's plan.

The SDT has removed R1.4.1 and re-worded R1.4: Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. ~~including at a minimum:~~ The SDT has deleted R1.4.2.

The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, the proposed change was not made to R2.

R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.

R4: The distinction between backup capabilities for RCs as compare to other entities arose from the FERC rulemaking relevant to this standard. FERC was emphatic that RCs have physical backup control centers. The SDT agrees that the emphasis should be on "what" as opposed to "how", and has changed the wording of the requirement to provide additional flexibility for RCs, but is constrained by FERC's direction on this point.

#8 – Commenter	Yes	No	Comment
R5: Having both R1 and R5 is a key element of the modification of EOP-08. One of the main criticisms of EOP-08 was that it only required a plan, and did not sufficiently require that the plan be realistic, effective, and tested. The presence of R5 is to make clear that to merely have a plan is not sufficient. You must be able to demonstrate that you have the capability to maintain system reliability in your backup configuration. R8 has been deleted as all entities now have the same 2 hour requirement. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. R10 deals with RC, BA, & TOPs while R4 is specific to the RC. The SDT has changed the wording in R10 (now R7) to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. R11 has been moved to R1.1: The location and method of implementation for providing backup functionality for a prolonged period of time.			
Madison Gas and Electric	x		R5 should be broken down into sub bullets, ie: R5.1, monitoring, R5.2, Control, R5.3, Logging, ect. R9 The last three words should be deleted "by a manager". Some entities may not have "manager" in the title of the position that writes and implements the Operating Plan. R10, the last sentence uses the words "any aspect" and needs to be removed. FERC Order 693, para. 663 states "... and the provision of a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center". The statement "any aspect" implies we can use nothing from the primary control center. What if I rely on security cameras to ensure Cyber security of both sites when dealing with physical security perimeters? Even though I may not be using the primary site for control I still have to protect it. I suggest new wording of "... does not depend on the primary control center for its functional operations". Or words to that effect. It is helpful to the Utility Industry if Measurements, Compliance, Data Retention, VSL's, etc. are in the draft standard. This allows us to see the whole picture of what is being proposed. It may even speed up the SAR process.
Response: R5: The phrase you are referring to is intended to clarify what types of capabilities are anticipated, not as an exhaustive list of required capabilities. If the SDT made the suggested change, each listed activity would become mandatory. Also, by implication any other activity required for reliability but not included on the list would be waived. The goal of the SDT with this requirement was to make clear that all reliability standards need to be adhered to in backup configuration and to provide examples of capabilities that would be anticipated to meet			

#8 – Commenter	Yes	No	Comment
those requirements. If an entity could meet all reliability standards without utilizing one of the items in this list they will not have violated R5 as written. If an entity has all these capabilities but still does not have what they need to comply with the standards then they would be in violation of R5 as written. This was the intent of the SDT. Changing the requirement as suggested would significantly change the impact of these two scenarios in a way the SDT believes would make it less appropriate. “By a Manager” has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. R10 deals with RC, BA, & TOPs while R4 is specific to the RC. The SDT has changed the wording in R10 (now R7) to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards.			
Manitoba Hydro Energy Board	x		Requirement R1.1 is too loose and is open to interpretation. Does R1.6 include the roles of support personnel including field personnel that may be required to staff stations during the transfer?
Response: R1.1 – The SDT feels that the requirement should not prescribe how a location or the method for backup is selected. Therefore, the requirement will remain. R1.7 – Who is involved is left up to the entity.			
Midwest Reliability Organization	x		During the transitional period were neither the primary or the backup control center are fully functionable, should the system operator have a copy of the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location? For example, lets say the primary control center is not functionable. The system operators become mobilized to make their way to the backup control center. They have everything they need, laptops, sattellite phones, etc but they don’t have a copy of the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location until, they get to the back up control center. What if they are not able to get to the backup control center, but could wirelessly access the backup control center capabilities, thus allowing them to perform but in a limited fashion since they don't have the transitional operating plan, a copy of the system one lines, and a list of all entities that they need to notify of a change in operating location? Thus, the SDT should address the transitional period in a more developed fashion perhaps allowing the system operators to operate from another location other than the backup control center if need be found and the system operators have that capability. R9. Each Reliability Coordinator, Balancing Authority, and applicable

#8 – Commenter	Yes	No	Comment
			Transmission Operator, shall have its Operating Plan for backup functionality reviewed and approved annually by a manager. The reference to the manager should be removed. NERC should only be concerned with having the RC, BA, and TOP annually review its plan. Requiring approval of anything internal is outside the scope of a NERC reliability standard, though they have used this concept in other standards.
Response: Comments regarding transition period: The SDT agrees that these would be prudent steps for most utilities to take during implementation of a transition to a backup facility and they would be important components of most Operating Plans for backup functionality. However the SDT believes it is important to specify what needs to be accomplished as opposed to the manner in which it needs to be accomplished and to establish a standard that can be applied to virtually all relevant organizations. Some utilities might accomplish their backup functionality without the physical movement of people (such as allowing another facility and staff to take over their responsibilities) in which case this requirement would not be applicable. The relevant sections of this standard require that the utility have a complete plan, that they can transition to the backup configuration in a reasonable amount of time, and that they contact appropriate parties during the transition. It is left to each utility to establish the best way to achieve those goals in its specific situation. Although most will include the steps you mention, the SDT believes the inclusion of those items in the standard would provide too much detail and inappropriately limit the flexibility of utilities to choose the most effective way to achieve the goals of the standard. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~.			
Nebraska Public Power District	x		Paragraph A.5. - Recommend a minimum of 36 months to implement the requirements in the standard after the effective date before the standard is auditable. Paragraph B.R9. - Delete, "by a manager". Each entitity should decide who has review and approval authority for its Operating Plan. Paragraph B.R9.1. - Requiring the Operating Plan to be updated and re-approved within sixty calendar days of any change is too restrictive. Major changes would require an update to the plan, but most changes could wait for the annual review. Paragraph B.R11. - Requiring a Backup Facility to be capable of operating for an indefinite period of time increases the complexity and adds unnecessary costs to the facility. Is this requirement mandating training facilities at the backup, including simulators, plus all the support staff for a Control Center. These functions are best addressed through an interium plan developed after the event

#8 – Commenter	Yes	No	Comment
			occurs; then, permanent facilities implemented with a plan to restore the primary. The actual situation that occurs will dictate how much and to what extent these are needed. General Comment: Our utility has spent a considerable amount on our primary facility to harden the facility and provide redundancy. Requiring us to invest in a fully operative backup facility redirects funding from needed infrastructure improvements in other areas. The actual probability and risk of needing a backup facility are very minimal, compared to transmission infrastructure improvements that clearly will provide value through increased ratings and reliability. Recommend the existing NERC requirements to have a plan to continue operations in the event its control center becomes inoperable be retained and the new requirements for a fully functional backup facility be eliminated. If this recommendation is not implemented, please provide justification from actual situations why these requirements are required.
Response: The Implementation Plan has been submitted with the second posting – and it indicates that entities will have at least 2 years to become compliant – starting with the date that the standard is approved by applicable regulatory authority approval. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. R9.1 (now R6.1) – The requirement is specific to changes in location, capabilities or communication protocols. Changes would normally be planned ahead of time before the changes were made. The SDT considers 1 year too long. R11 – The SDT believes that it is important to realize that the length of time that you may be at your backup can't be predicted and that the use of the term 'prolonged' is appropriate. The plan should be for the long-term. An entity must be prepared to achieve compliance and maintain the reliability of the BES while in a backup mode. R11 has been moved to R1.1 and the term indefinite has been changed to 'prolonged'. The location and method of implementation for providing backup functionality for a prolonged period of time. General Comment: Even though the probability is very low, and you have a hardened Primary facility, there still needs to be a requirement for a backup plan for the loss of Primary functionality. The requirement does not say a backup facility - the requirement is backup functionality, therfore one could contract for service .			
Northeast Utilities	x		R9.1 "…within sixty calendar days of any changes to the backup location, capabilities, or communication protocols." is wide open. It seems there could be changes made that improve capabilities or communication protocols that would not meet the threshold of a revision to the plan, such as a tool added to the primary center that works similarly at the Backup Center. The words "any changes" are too broad, possibly replace with "significant changes that impact the Operating Plan….." or similar.

#8 – Commenter	Yes	No	Comment
Response: R9.1 (now R6.1) – The requirement is specific to changes in location, capabilities or communication protocols. Significant changes would normally be planned ahead of time before the changes were made. The requirement has been changed and replaces 'communication protocol' with 'contact information'. The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~ contact information.			
Oncor Electric Delivery Company	x		Requirement R3 is a step in the right direction. The intent is to be sure that local control centers that provide significant BES operating activities but which are not TOPs themselves also have backup capability. The requirement as written is subject to significant interpretation and it isn't clear whether the requirement achieves the desired outcome. For example, one interpretation would be that the TOP backup plan has to consider being able to operate with the local control center through its backup plan, but a more robust interpretation would address whether the backup facility plan of the TOP has also taken care of the loss of the primary control center for the local control center. This issue would typically arise when a Transmission Owner operates a primary control center that is important to BES reliability, but which is not themselves a Transmission Operator. The direct method would be to make these Transmission Owners a responsible entity. However, if the intent is to get to this concern through the Transmission Operator, then additional clarity in R3 is necessary. A very important issue that must be dealt with in this standard is the issue of enforcement of this standard following loss of the primary control center. There are two distinct dimensions to this issue. One is that during the transition period from the primary facility to the backup capability it needs to be recognized that not all reliability functions will be able to be accomplished. Specific waiver from compliance is very important during this transition period. Unless such a waiver is provided, the standard will essentially require that zero transition time is allowed between loss of primary control center and full functionality of backup capability. Such a requirement would essentially require a fully staffed hot backup capability at all times. Oncor believes such a requirement will be too expensive and not warranted. A second dimension to this compliance concern follows the loss of the primary control center itself. After the backup capability is fully functioning, compliance with all reliability standards would be expected, but the concern is whether compliance with EOP-008 itself would still be required. Unless it is clear that the provision of a backup capability is not required during the period that the primary capability has been lost, the result will be that a backup to the backup capability must be provided at all times. Oncor strongly believes that there is no credible reliability argument that would indicate that

#8 – Commenter	Yes	No	Comment
			such a 3 deep backup capability is warranted, and without such a waiver the standard would impose unreasonable costs on the industry.

Response: R3: The SDT feels it is necessary to point out that the registered TOP is responsible to ensure that operations required to maintain the reliability of the BES, including those they delegate, must be backed up. The SDT has changed the wording of R3 to: Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality ~~those operations~~ in its Operating Plan for backup functionality.

The SDT has addressed the issue of what happens following the loss of a control center in the revised R4 & R5.

R4**:** Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator.

R5: Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively.

#8 – Commenter	Yes	No	Comment
PJM Interconnection	x		We suggest requirement 8 be rewritten to read; "For each RC, TOP and BA, the Operating Plan for backup functionality shall include a list of all entities that need to be notified of a change in operating locations." R8.1 and R8.2 can be eliminated since the time requirements suggested above are the same for BA, TOP, RC.

Response: Requirement R8 has been deleted. The requirement to identify the entities that must be notified if there is a "change in operating locations" is now in R1.6.1 as part of the Operating Plan. R8.1 and R8.2 have been deleted.

#8 – Commenter	Yes	No	Comment
Santee Cooper	x		We are unsure as to the definition of what starts the transition period and what ends the transition period to the backup control center. We believe further detail is required. Regarding R11 - what is an "indefinite period of time" and what would be a reasonable measure? Regarding R4 - We believe the term "replicates" should be removed, as this may

#8 – Commenter	Yes	No	Comment
			not be physically possible. Perhaps a distiction between types of functionality required would be more appropriate. We certainly disagree with any thought process that would require continual staffing of the backup control center. If entities can invoke their backup plan and have backup functionality with two to three hours, this should be sufficient, especially given the odds of the number of times it will be needed.
Response: Transition starts with the event that results in the loss of functionality at the primary control center and ends with the restoration of functionality at the backup. R11 has been moved to R1.1 and the term 'indefinite' has been changed to 'prolonged'. The location and method of implementation for providing backup functionality for a prolonged period of time. R4 Comment Paragraph 1: We interpret the comment as inferring a requirement to duplicate functionality of the primary control center beyond that which is required to maintain compliance with Reliability Standards. The requirement has been rewritten to make clear that such is not the intent. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another ~~Reliability Coordinator's~~ entity's ~~primary~~ control center) that ~~replicates~~ provides the functionality ~~of its primary control center facility as~~ required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. Paragraph 2: It is not the intent to require a continually staffed backup control center. The SDT does not believe the draft language can be read to imply such a requirement.			
Sierra Pacific Resources Transm.			Use of "Plan", "Process" and "Procedure": I found myself a bit confused as to the terminology used here. The Standard starts out by defining that there shall be an Operating Plan for the backup center, which is to include a number of items. Later, the Standard introduces the terms "Operating Process" (R1.4 and R1.5) and even "Operating Procedure" (R8.1, R8.2). Many will interpret these terms to be synonymous unless there is some distinction provided in the Standard. R9 Annual Review and Approval by a "manager": This term seemed a bit loose to me as I reveiwed the Standard. As it is not a defined term, it is left open to interpretation as to what level individual can act as the "manager". Perhaps there should be some clarification such as "...a manager having functional responsibility for Control Center Operation". R10 Dependency Upon Primary Control Center: This Requirement prohibits any dependency upon the primary center for any aspect of the backup center operation. Such a strict Requirement may necessitate a transition period to achieve compliance. Most BUCC operations have some level of dependency upon the primary, and we strive to minimize that. The BUCC will likely have a

#8 – Commenter	Yes	No	Comment
			reduced, but adequate, level of functionality if the primary were to be completely destroyed, but might have far greater capability if some of the primary control center facilities remain active. Note that this Standard does not specifically prescribe how much visiblity or functionality the BUCC must have. Document Simplification Suggestions: Since R1 describes the Operating Plan and its minimum included items, I would suggest moving the text of R8 into a sub-item of R1, as R1.7. The draft R8 talks about another item that is to be included in the Operating Plan. The sub items R8.1 and R8.2 don't seem to bear any relationship to the parent R8. These Requirements are for situational awareness if the implementation of the BUCC operation is to last more than 2 hours, and they fit better as sub-items under R7, which speaks to the transition period. I'd therefore suggest moving these under R7 as R7.1 and R7.2.
Response: Operating Plan, Operating Process, and Operating Procedure are all defined terms in the currently approved NERC Glossary and were used based on those respective definitions. Therefore, no changes were made by the SDT. R8 has been deleted and all applicable entities now have the same time requirement. "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality ~~reviewed and approved annually by a manager~~. The SDT has changed the wording in R10 (now R7) to read: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for ~~any aspect of its operation~~ any functionality required to maintain compliance with Reliability Standards. The SDT did move the intent of R8 into R1.6.1. R8.1 and R8.2 were deleted as the revised standard requires all responsible entities to have a plan to fully implement its backup plan and get backup functionality up and running that is less than two hours.			
SPP ORWG	x		In Requirement 9 add the following phrase after manager: …responsible for the operation of the primary control center. We would suggest that R2 be expanded to require copies of the Operating Plan be shared with all entities/locations having an active role in the plan.
Response: "By a Manager" has been removed from the requirement. The revised document will state under R6: Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall ~~have~~ annually review and approve its Operating Plan for backup functionality			

#8 – Commenter	Yes	No	Comment
~~reviewed and approved annually~~ ~~by a manager~~. R2: The SDT feels that the Operating Plan must be located at the primary and backup locations. Distribution of the plan to other locations is at the discretion of the entity. Therefore, the proposed change was not made to R2.			
WECC Operating Practices Subc.	x		Clarity needs to be added to R 9.1 regarding the definition of "communication protocal"? For example, entities do not want to have to update the operating plan for changes such as an RTU communication protocol.
Response: The key phrase is 'backup functionality.' If the RTU communication protocol significantly affects the Backup functionality then it needs to be reflected within the plan in the required timeframe. R9.1 has been changed and 'communication protocols' has been replaced with 'contact information'. The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~ contact information.			
Allegheny Power		x	
Comision Federal de Electricidad		x	
MA Dept. of Public Utilities			No comment.
NY State Dept. of Public Service			No comment.
PacifiCorp		x	
Pacific Gas and Electric Company			No comment.
PS Commission of South Carolina		x	
Sacramento Municipal Utility Dist.		x	No other comments at this time.
Sierra Pacific Power Company			No comment.
Tampa Electric Company		x	
Xcel Energy			No comment.
Response: Thank you for your response.			

Implementation Plan for EOP-008-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

EOP-008-1 — Loss of Control Center Functionality

Revision to Sections of Approved Standards and Definitions

There are no new or revised definitions in the proposed standard.

Compliance with Standard

EOP-008-1: Loss of Control Center Functionality	Functions That Must Comply With the Associated Requirements		
	Reliability Coordinator	Balancing Authority	Applicable Transmission Operator
R1	X	X	X
R2	X	X	X
R3			X
R4	X		
R5		X	X
R6	X	X	X
R7	X	X	X
R8	X	X	X
R9	X	X	X

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard.

Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with the requirements.

EOP-008-0 is retired when EOP-008-1 goes into effect.

All requirements of EOP-008-1 will go into effect the first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 2nd Draft of Standards for Backup Facilities (Project 2006-04)

Please **DO NOT** use this form to submit comments on the 2nd draft of the standard for Backup Facilities (Project 2006-04). Comments must be submitted by October 9, 2008 by using the electronic comment form provided at the link below. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Backup_Facilities.html

Background Information:

The Backup Facilities Standard Drafting Team (BF SDT) has made significant changes to the second posting of EOP-008-1 based on comments received from the industry. Major changes included:

- A revision to the applicability of the Transmission Operator (Section 4.1.2). This was done to attempt to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV unless the Regional Entity deems them as a critical part of the Interconnection.
- Changing the transition timeframes so that they are equivalent for all applicable entities. (R1.5)
- A short description of what needs to be in the Operating Process. (R1.6)

In addition, VRFs, Time Horizons, Measures, Compliance elements including VSLs, and an Implementation Plan have been supplied with this version.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this standard.

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. The SDT has made a change in the applicability of the Transmission Operator (see Section 4.1.2). Do you agree with the change that was made? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has made the transition timeframes equivalent for all applicable entities as shown in Requirement R1.5. Do you agree with this change? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

Comments:

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

☐ Yes

☐ No

Comments:

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

☐ Yes

☐ No

Comments:

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

☐ Yes

☐ No

Comments:

6. The SDT has provided an Implementation Plan with this posting. Do you agree with the implementation timeframe that shows all requirements going into effect on the same time/date? If not, please provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

7. Are there any other issues that need to be addressed? Please be specific.

☐ Yes

☐ No

Comments:

8. Do you believe this standard will help deliver an adequate level of reliability?

☐ Yes

☐ No

Comments:

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q09. The current draft is the second iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard.	May 2008
2. Submit second revision of standard.	July 2008
3. Respond to comments from second posting of standard.	November 2008
4. Submit third revision of standard.	December 2008
5. Submit standard for balloting.	March 2009
6. Submit standard for recirculation balloting.	April 2009
7. Submit standard to BOT.	April 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES).

   4.1.3. Balancing Authority.

5. **Effective Date:** All requirements of EOP-008-1 become effective the first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have an Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This Operating Plan for backup functionality shall include the following at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R1.1. The location and method of implementation for providing backup functionality for a prolonged period of time.

R1.2. An overview of the elements required to support the backup functionality. These elements shall include, at a minimum:

R1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES.

R1.2.2. Data communications.

R1.2.3. Voice communications.

R1.2.4. Power source(s).

R1.2.5. Physical and cyber security.

R1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

R1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

R1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running that is less than two hours.

R1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running. The Operating Process shall include:

R1.6.1. A list of all entities to notify when there is a change in operating locations.

R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.

R1.7. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a copy of its Operating Plan for backup functionality located in its primary control center and at the location supporting backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R4. Each Reliability Coordinator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R5. Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R6. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R6.1. The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup location, capabilities, or contact information.

R7. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall conduct an annual test of its Operating Plan that includes: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8.1. A demonstration of the transition time between the primary control center and the initiation of backup functionality.

R8.2. Actual implementation or test operations of the backup functionality for a minimum of two continuous hours.

R8.3. Test results shall be documented and lessons learned noted and incorporated in subsequent revisions of the Operating Plan for backup functionality.

R9. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months, shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable.

M2. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, with evidence of its last issue, located in its primary control center and at the location supporting backup functionality.

M3. Each applicable Transmission Operator directing BES operations through other entities shall provide evidence that it has included provisions for the loss of such entity's control functionality in its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, for backup functionality in accordance with Requirement R3.

M4. Each Reliability Coordinator shall provide dated evidence that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator in accordance with Requirement R4.

M5. Each Balancing Authority and applicable Transmission Operator shall provide dated evidence that it has demonstrated that it's backup functionality (provided either through a backup control center facility or contracted services) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority or Transmission Operator respectively in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall have evidence that it's dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, with evidence of its last issue, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the backup location, capabilities, or contact information in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have dated evidence that its backup capability does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall provide evidence such as dated records, that it has tested its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, and that test results and lessons learned from such testing are noted and incorporated in subsequent revisions of its Operating Plan for backup functionality in accordance with Requirement R8.

M9. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months, shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability in accordance with Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the current year and three previous years in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain a dated, current, in force copy of its

Operating Plan for backup functionality, with evidence of its last issue, located in its primary control center and at the location supporting backup functionality, for the current year, in accordance with Measurement M2.

- Each applicable Transmission Operator directing BES operations through other entities shall retain its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, providing evidence that it has included provisions for the loss of such entity's control functionality for the current year and three previous years, in accordance with Measurement M3.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4 that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator in accordance with Measurement M4.
- Each Balancing Authority and applicable Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall retain evidence for the current year and three previous years, that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the backup location, capabilities, or contact information in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its backup capability does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, in accordance with Measurement M8.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months, shall retain evidence for the

current in force document and any such documents in force since its last compliance audit, that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability in accordance with Measurement M9.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is missing one of the sub-requirements or the plan is not dated with evidence of its last issue.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is missing two of the sub-requirements.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is missing three or more of the sub-requirements.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator does not have an Operating Plan for backup functionality.
R2.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is not located in one of its control locations.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is not located in either of its control locations.	N/A	N/A
R3.	The applicable Transmission Operator directing BES operations through other entities has not included provisions for the loss of such entity's control functionality for 10% or less of its applicable entities in its Operating Plan for backup functionality.	The applicable Transmission Operator directing BES operations through other entities has not included provisions for the loss of such entity's control functionality for more than 10% and less than 25% of its applicable entities in its Operating Plan for backup functionality.	The applicable Transmission Operator directing BES operations through other entities has not included provisions for the loss of such entity's control functionality for more than 25% of its applicable entities in its Operating Plan for backup functionality.	The applicable Transmission Operator directing BES operations through other entities has not included provisions for the loss of any such entity's control functionality in its Operating Plan for backup functionality.
R4.	The Reliability Coordinator has demonstrated that it has a	The Reliability Coordinator has demonstrated that it has	The Reliability Coordinator has demonstrated that it has	The Reliability Coordinator has not demonstrated that it has a

R#	Lower	Moderate	High	Severe
	backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4 but it only provides the functionality required for maintaining compliance with 90% of the Reliability Standards applicable to the Reliability Coordinator or the evidence of the demonstration is not dated.	a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4 but it only provides the functionality required for maintaining compliance with 80% of the Reliability Standards applicable to the Reliability Coordinator.	a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4 but it only provides the functionality required for maintaining compliance with 70% of the Reliability Standards applicable to the Reliability Coordinator.	backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4.
R5.	The Balancing Authority or applicable Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 but it only includes monitoring, control, logging, and alarming sufficient for maintaining compliance with 90% of the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively or its	The Balancing Authority or applicable Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 but it only includes monitoring, control, logging, and alarming sufficient for maintaining compliance with 80% of the Reliability Standards applicable to a Balancing Authority and	The Balancing Authority or applicable Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 but it only includes monitoring, control, logging, and alarming sufficient for maintaining compliance with 70% of the Reliability Standards applicable to a Balancing Authority and	The Balancing Authority or applicable Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5.

R#	Lower	Moderate	High	Severe
	evidence is not dated.	Transmission Operator respectively.	Transmission Operator respectively.	
R6.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was done in more than twelve calendar months and less than or equal to fifteen calendar months or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes to the backup location, capabilities, or contact information.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was done in more than fifteen calendar months or that it was updated more than ninety calendar days after any changes to the backup location, capabilities, or contact information.	N/A	N/A
R7.	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator's dated evidence shows that its backup capability does depend on the primary control center for the functionality required to maintain compliance with

R#	Lower	Moderate	High	Severe
				Reliability Standards.
R8.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has provided evidence, such as dated records, that it has tested its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, through actual implementation or test operations for less than two continuous hours, or it has failed to demonstrate that the transition time period is less than or equal to two hours, or it was done in more than twelve calendar months or test results and lessons learned were not incorporated in subsequent revisions of the Operating Plan for backup functionality. .	N/A	N/A	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has not annually tested its dated, current, in force Operating Plan for backup functionality.
R9.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator that has experienced a loss of their primary or backup capability and that	N/A	N/A	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates

R#	Lower	Moderate	High	Severe
	anticipates that the loss of primary or backup capability would last for more than six calendar months, has provided evidence that a plan has been submitted to its Regional Entity showing how it will re-establish backup capability but it was submitted in more than six calendar months.			that the loss of primary or backup capability would last for more than six calendar months, has not submitted a plan to its Regional Entity showing how it will re-establish backup.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q09. The current draft is the second iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard.	May 2008
2. Submit second revision of standard.	July 2008
3. Respond to comments from second posting of standard.	November 2008
4. Submit third revision of standard.	December 2008
5. Submit standard for balloting.	March 2009
6. Submit standard for recirculation balloting.	April 2009
7. Submit standard to BOT.	April 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

4.1. Functional Entity

4.1.1. Reliability Coordinator.

~~**4.1.2.** Transmission Operator with control of facilities that are designated as Critical Assets or with defined Interconnection Reliability Operating Limits (IROLs)~~

4.1.2. Transmission Operator operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES).

4.1.3. Balancing Authority.

5. **Effective Date:** ~~TBD~~ All requirements of EOP-008-1 become effective the first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have an Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This Operating Plan for backup functionality shall include the following at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R1.1. The location and method of implementation for providing backup functionality for a prolonged period of time.

R1.2. ~~A high level~~ An overview of the elements required to support the backup functionality. These elements shall include, at a minimum:

R1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES.

R1.2.2. Data communications.

R1.2.3. Voice communications.

R1.2.4. Power source(s).

R1.2.5. Physical and cyber security.

R1.3. An Operating Process for keeping the backup functionality ~~current~~consistent with the primary control center.

R1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality ~~including, at a minimum:~~.

~~R1.4.1.~~ ~~Criteria for evacuation of the primary control center including the decision authority for initiating the Operating Plan for backup functionality and the Operating Process for initiation of backup functionality~~

R1.5. ~~Criteria for returning operations support to the primary control center including the decision authority and the Operating Process for returning to the primary control center~~A transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running that is less than two hours.

R1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to get backup functionality up and running. The Operating Process shall include:

R1.6.1. A list of all entities to notify when there is a change in operating locations.

R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary/backup functionality.

R1.7. Identification of the roles for ~~all involved~~ personnel involved during the initiation and implementation of the Operating Plan for backup functionality ~~and for the return to the primary control center~~.

R2. ~~A~~Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a copy of ~~the~~its Operating Plan for backup functionality ~~shall be~~ located in ~~the~~its primary control center and at the location supporting backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each applicable Transmission Operator directing BES operations through other entities shall include ~~those operations~~provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R4.~~~~Each Reliability Coordinator shall have a backup control center facility that replicates the functionality of its primary control center facility as required for maintaining compliance with all reliability standards applicable to the~~ Each Reliability Coordinator~~. This~~ shall, during the time period when the primary control center functionality and the backup functionality ~~can be~~ are both available for use, have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. ~~Coordinator's primary control center.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R4.

~~R4.~~R5. Each Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup ~~functionality~~functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all ~~reliability standards~~Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively. ~~This backup functionality can be provided either through a backup control center facility or contracted services.~~*[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~**R6.** For Reliability Coordinators, the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running shall be planned to be less than two hours.~~

~~**R7.** For each Balancing Authority and applicable Transmission Operator, the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running shall be planned to be less than six hours.~~

~~R5.~~R6. ~~For each~~Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, ~~the~~ shall annually review and approve its Operating Plan for backup functionality ~~shall include a list of all entities that need to be notified of a change in operating locations.~~. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

~~**R8.1.** For each applicable Transmission Operator, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the situational awareness and control of facilities with defined Interconnection Reliability Operating Limits (IROLs) beyond the two hour time period.~~

~~**R8.2.** For each Balancing Authority, if the transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running is planned to be greater than two hours, then the Operating Procedure shall additionally include processes that will ensure the calculation and control of its ACE beyond the two hour time period.~~

~~**R9.** For each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator,~~ The update and approval of the Operating Plan for backup functionality shall take place~~be documented and shall be reviewed and approved annually by a manager.~~

~~R5.1.~~R6.1. ~~Operating Plans for backup functionality shall be updated and approved~~~~take place~~ within sixty calendar days of any changes to the backup location, capabilities, or ~~communication protocols~~contact information.

~~R6.~~R7. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup capability that does not depend on the primary control center for any ~~aspect of its operation.~~ functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R7.~~**R8.** Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall ~~have backup capability that is capable of operating for~~ conduct an ~~indefinite period of time.~~ annual test of its Operating Plan that includes: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8.1. A demonstration of the transition time between the primary control center and the initiation of backup functionality.

R8.2. Actual implementation or test operations of the backup functionality for a minimum of two continuous hours.

R8.3. Test results shall be documented and lessons learned noted and incorporated in subsequent revisions of the Operating Plan for backup functionality.

~~R12.~~ Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator ~~shall test its Operating Plan for backup functionality through actual implementation or test operations for~~that has experienced a ~~minimum of two hours annually.~~

R9. ~~Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator~~ loss of ~~their~~its primary or backup capability and that anticipates that ~~a total~~the loss of primary or backup capability will last for more than six calendar months, shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

The Measures and Compliance elements are all new and are shown without "track changes" to make them easier to read.

M1. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable.

M2. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, with evidence of its last issue, located in its primary control center and at the location supporting backup functionality.

M3. Each applicable Transmission Operator directing BES operations through other entities shall provide evidence that it has included provisions for the loss of such entity's control functionality in its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, for backup functionality in accordance with Requirement R3.

M4. Each Reliability Coordinator shall provide dated evidence that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator in accordance with Requirement R4.

M5. Each Balancing Authority and applicable Transmission Operator shall provide dated evidence that it has demonstrated that it's backup functionality (provided either through a backup control center facility or contracted services) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority or Transmission Operator respectively in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall have evidence that it's dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, with evidence of its last issue, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the backup location, capabilities, or contact information in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have dated evidence that its backup capability does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall provide evidence such as dated records, that it has tested its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, and that test results and lessons learned from such testing are noted and incorporated in subsequent revisions of its Operating Plan for backup functionality in accordance with Requirement R8.

M9. Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months, shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability in accordance with Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the current year and three previous years in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, located in its primary control center and at the location supporting backup functionality, for the current year, in accordance with Measurement M2.
- Each applicable Transmission Operator directing BES operations through other entities shall retain its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, providing evidence that it has included provisions for the loss of such entity's control functionality for the current year and three previous years, in accordance with Measurement M3.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4 that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator in accordance with Measurement M4.
- Each Balancing Authority and applicable Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator, shall retain evidence for the current year and three previous years, that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the backup location, capabilities, or contact information in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its backup capability does not depend on the primary control center

for any functionality required to maintain compliance with Reliability Standards in accordance with Measurement M7.

- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, in accordance with Measurement M8.
- Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months, shall retain evidence for the current in force document and any such documents in force since its last compliance audit, that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability in accordance with Measurement M9.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is missing one of the sub-requirements or the plan is not dated with evidence of its last issue.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is missing two of the sub-requirements.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is missing three or more of the sub-requirements.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator does not have an Operating Plan for backup functionality.
R2.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is not located in one of its control locations.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has an Operating Plan for backup functionality but the plan is not located in either of its control locations.	N/A	N/A
R3.	The applicable Transmission Operator directing BES operations through other entities has not included provisions for the loss of such entity's control functionality for 10% or less of its applicable entities in its Operating Plan for backup functionality.	The applicable Transmission Operator directing BES operations through other entities has not included provisions for the loss of such entity's control functionality for more than 10% and less than 25% of its applicable entities in its Operating Plan for backup functionality.	The applicable Transmission Operator directing BES operations through other entities has not included provisions for the loss of such entity's control functionality for more than 25% of its applicable entities in its Operating Plan for backup functionality.	The applicable Transmission Operator directing BES operations through other entities has not included provisions for the loss of any such entity's control functionality in its Operating Plan for backup functionality.
R4.	The Reliability Coordinator has demonstrated that it has a	The Reliability Coordinator has demonstrated that it has	The Reliability Coordinator has demonstrated that it has	The Reliability Coordinator has not demonstrated that it has a

R#	Lower	Moderate	High	Severe
	backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4 but it only provides the functionality required for maintaining compliance with 90% of the Reliability Standards applicable to the Reliability Coordinator or the evidence of the demonstration is not dated.	a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4 but it only provides the functionality required for maintaining compliance with 80% of the Reliability Standards applicable to the Reliability Coordinator.	a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4 but it only provides the functionality required for maintaining compliance with 70% of the Reliability Standards applicable to the Reliability Coordinator.	backup control center facility (provided through its own dedicated backup facility or at another entity's control center) in accordance with requirement R4.
R5.	The Balancing Authority or applicable Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 but it only includes monitoring, control, logging, and alarming sufficient for maintaining compliance with 90% of the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively or its	The Balancing Authority or applicable Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 but it only includes monitoring, control, logging, and alarming sufficient for maintaining compliance with 80% of the Reliability Standards applicable to a Balancing Authority and	The Balancing Authority or applicable Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 but it only includes monitoring, control, logging, and alarming sufficient for maintaining compliance with 70% of the Reliability Standards applicable to a Balancing Authority and	The Balancing Authority or applicable Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5.

R#	Lower	Moderate	High	Severe
	evidence is not dated.	Transmission Operator respectively.	Transmission Operator respectively.	
R6.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was done in more than twelve calendar months and less than or equal to fifteen calendar months or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes to the backup location, capabilities, or contact information.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was done in more than fifteen calendar months or that it was updated more than ninety calendar days after any changes to the backup location, capabilities, or contact information.	N/A	N/A
R7.	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator's dated evidence shows that its backup capability does depend on the primary control center for the functionality required to maintain compliance with

R#	Lower	Moderate	High	Severe
				Reliability Standards.
R8.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has provided evidence, such as dated records, that it has tested its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, through actual implementation or test operations for less than two continuous hours, or it has failed to demonstrate that the transition time period is less than or equal to two hours, or it was done in more than twelve calendar months or test results and lessons learned were not incorporated in subsequent revisions of the Operating Plan for backup functionality. .	N/A	N/A	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator has not annually tested its dated, current, in force Operating Plan for backup functionality.
R9.	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator that has experienced a loss of their primary or backup capability and that	N/A	N/A	The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates

R#	Lower	Moderate	High	Severe
	anticipates that the loss of primary or backup capability would last for more than six calendar months, has provided evidence that a plan has been submitted to its Regional Entity showing how it will re-establish backup capability but it was submitted in more than six calendar months.			that the loss of primary or backup capability would last for more than six calendar months, has not submitted a plan to its Regional Entity showing how it will re-establish backup.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

Standards Announcement

Comment Period Open

Now available at: http://www.nerc.com/filez/standards/Backup_Facilities.html

Comment Period for Project 2006-04 — Backup Facilities Opens August 26, 2008

The Backup Facilities Standard Drafting Team has posted its second draft of a set of proposed requirements for EOP-008-1 — Loss of Control Center Functionality for a 45-day comment period through October 9, 2008.

The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable.

In the first draft, the drafting team made many changes to this "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The second draft of EOP-008-1 includes significant changes based on comments received from the industry, such as the following:

- A revision to the applicability of the Transmission Operator. This was done to attempt to eliminate the burden on a Transmission Operator that just has a radial connection to the Bulk Electric System under 200 kV unless the Regional Entity deems them as a critical part of the Interconnection.
- Changing the transition time periods so that they are equivalent for all applicable entities.
- A short description of what needs to be in the Operating Process for the transition time period.

The second draft also includes Violation Risk Factors, Time Horizons, Measures, Compliance elements, including Violation Severity Levels, and an Implementation Plan.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

If you need an off-line, unofficial copy of the questions in the comment form, a copy is posted at the following site:

http://www.nerc.com/filez/standards/Backup_Facilities.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Shaun Streeter,
Standards Program Administrator, at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (38 Responses)
Name (24 Responses)
Organization (24 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Contact Organization (14 Responses)
Question 1 (37 Responses)
Question 1 Comments (38 Responses)
Question 2 (36 Responses)
Question 2 Comments (38 Responses)
Question 3 (33 Responses)
Question 3 Comments (38 Responses)
Question 4 (36 Responses)
Question 4 Comments (38 Responses)
Question 5 (32 Responses)
Question 5 Comments (38 Responses)
Question 6 (34 Responses)
Question 6 Comments (38 Responses)
Question 7 (36 Responses)
Question 7 Comments (38 Responses)
Question 8 (36 Responses)
Question 8 Comments (38 Responses)

-	-
	Individual
	Jianmei Chai
	Consumers Energy Company
	Yes
	Yes
	No
	M7. calls for "shall have dated evidence that its backup capability does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7." This is subjective as to what that evidence consists of and leaves to much to interpertation. Is a letter stating there is no dependance suffice? Will it suffice regardless of who the auditor is?
	Yes
	This standard is overbaring and requires far more documentation than is needed to maintain reliability and accomplish the goals of adequateds back-up facillities. For example, could the annual test be considered the review of the Operating Plan? Is it sufficent documention that proof a test has been conducted and was successful in operating the system?
	No
	When drafting standards we should keep in mind the primary goal. That goal is to provide a high level of reliability. There needs to be a balance between the actions of making our operations reliable or taking away from that effort by putting a program in place that majority of effort is administrative, thus detracking from the original goal. Back-up facillities are needed but the amount of data being requested here seems to be excessive burdan that changes the focus from preparing for back-up operations to preparing for a NERC audit.
	Group
	WECC Reliability Coordinator Comment Working Group

	Linda Perez
	WECC
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	No
	Yes
	Individual
	Todd Lietz
	Puget Sound Energy
	Yes
	Since there are many differences in size and effect on the BES of the many registered TOPs, there should be a mechanism where the RRO or RC determines the level of risk an entity poses to their area should they lose their control center. Just because a small entity has a line or two that fits the all encompassing defintion of BES, does not place the same burden on the system as a large path operator with hundreds of lines. Some entities are large enough where they should have a staffed backup facility. Implementation of costly plans simply due to a registration type that does nothing to increase reliability should be avoided. Costs are passed on to customers. Simply stating it is for reliability does not justify it to them.
	Yes
	Yes
	No
	M.3 - There needs to be clarification in either the requirement or the measure as to the definition of "directing", "entity" and "control functionality". Was this intended to be the TOP that is acting as a host for a DP, or say a GOP? Does the loss of functionality mean a RTU being down now must be addressed in the loss of control center plan for the TOP? Does this even need to be a requirement since R.5 is so vague and encompassing? Why just the TOP and not BA's that are providing regulation services of acting as a host to others? The measurement and requirement are open to interpretation. Both need to be clear, concise and measurable. M.6 - The requirement and measure ask for approval. What level of approval does the SDT expect for this? If the SDT does not feel the need to specify, then why have it. M.7 - The measure requires dated evidence of a negative statement. Proving a negative in an audit is not easy. Could a statement in the current, dated Operating Plan stating it does not rely on the primary facility be sufficent evidence? I know the SDT does not determine what is acceptable to an auditor, but measures asking for dated proof that something does not exist, did not happen or are not dependent should be avoided. Will I have to provide dated evidence that I did not lose my primary capability for six months in M.9 as well? M.8 Providing evidence that the Operating Plan and backup functionality were tested is definitely needed. The current wording of the requirement and measure could be interpreted as each version of the plan must be tested. If a test is done, and the plan is subsequently updated with lessons learned as required in R8.3, the new dated, current, in force plan would not have evidence of being tested. I know this is petty and just semantics, but compliance people may take it literally.
	No

	R.3 Since the terms of this requirement and measure are not clearly defined, there is no clear way to determine what percentage was met. R.5 What mechanism will be used to determine the percentage of standards can be or could be met?
	No
	This depends on the interpetation of R.5. The statement of "during the time period when the primary control center and the back up functionality are both available for use" is vague. Does this refer to the time period when an entity is in the process of constructing a backup facility or is it referring to the transition time in R.1.5? If it is the time of R.1.5, this is a huge monetary and resource burden. Essentially it would require an entity to have a staffed fully redundant backup facility 24x7, or a contract with another entity with 24x7 staff properly trained to monitor, control, log and respond to alarms on another entities entire system. If this is the case, then 24 months may not be adequate.
	Yes
	R.5 needs further clarification as stated in my response to the previous question. R.1.6.2. The definition of "actions to manage risk" is vague. This again points to R.5. If an entity has notified affected entitites that it is in the process of transitioning to the back up facility and made notifications to implement the plan, aren't these actions to manage risk to the BES? I am not sure what the SDT had in mind with this requirement.
	Yes
	However, I am concerned that many of the additional requirements of this standard do not add to reliability, just increase documentation requirements, staffing and costs for a minimal increase in reliability. I am not aware of an instance where an entity has implemeted their loss of control center plan and placed the BES in a perilous situation. There are actually few entities large enough to have this affect. I am fully on board with RCs having the capabilities prescribed in this standard, but there are many entites for which this is overkill. Perhaps the standard should place the burden on the RRO or RC to detemine adequate levels of backup facilites for the BAs and TOPs under their jurisdiction.
	Individual
	Randy Schimka
	San Diego Gas and Electric
	Yes
	Yes
	Yes
	Yes
	No
	We would like to see additional consistency used between the Requirements verbiage and the Violation Severity Level table verbiage, particularly with respect to R8 (although this same terminology appears elsewhere as well). The Requirements verbiage for R8 uses the term "annual" in the description when referring to testing, whereas the VSL table refers to a period of "12 calendar months." In discussing the terminology with others, there seems to be a difference of opinion of the definition of the word "annual" when it comes to NERC compliance. Some people think that the particular requirement can be fulfilled anytime within a particular calendar year (one year in July and the following year in September and the following year in May, etc.), whereas others believe that an August 1 test date in one year means that the same testing must be completed before August 1 in the following year to remain in compliance. The issue with the latter interpretation of "annual" is that the requirement will suffer from date creep every year, as the entity completes the compliance requirement in advance of the prior year. Over time, this date creep will ultimately cause entities to have to perform testing and other requirements at times of the year when we don't want to do them (i.e. summer periods) or do them too far in advance. We believe the requirement should be spelled out specifically so the definition is crystal clear (i.e every 11 months plus or minus 30 days).
	Yes
	Yes
	R5 - We would like to get some clarification on Requirement 5, particularly with respect to the opening sentence that refers to the time period when primary and backup control center functionality is available for use, then the requirement is to have backup functionality. If both primary and backup control centers are available for use, doesn't that automatically mean that backup functionality is available? Please clarify the meaning of this

	Requirement. R6.1 - We would like further clarification to the term "changes to the backup capabilities" that would require an update and approval of the Operating Plan. What are examples of changes to backup capabilities that would trigger an update of the Operating Plan? What are examples of changes to backup capabilities that are considered more "minor" that wouldn't require an update?
	Yes
	Individual
	Dan Brotzman
	ComEd / Exelon
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	R5 addresses maintaining the backup functionality that includes monitoring, control, logging, and alarming. M5 requires dated evidence (documentation) that you have demonstrated the backup functionality for the requirements in R5. However R8.2 addresses the testing of the backup functionality through actual implementation or test operation for a minimum of two consecutive hours. The requirements of R5 should be incorporated into R8.2 and therefore R5 eliminated as a standalone requirement. As it is currently written in draft 2, R5 & R8.2 are redundant and M5 & M8 are redundant in terms of practical application and verification of compliance.
	Yes
	Group
	Entergy System Planning & Operations (Generation & Marketing)
	Will Franklin
	Entergy
	No
	No
	It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. A statistical risk analysis would be ideal to determine this allowable time, if a valid model exists. If an arbitrary value is used, then an industry survey or something similar (experts/EPRI) may be appropriate (e.g. EPRI Project RP2473-68)
	Yes
	Yes
	No
	Consider adding to the implementation requirement that entities comply within the timeframe stated or if an entity believes it will take longer than the specified time to become compliant, allowing entities to apply for an extension

	to the timeframe stated if that entity can justify the need for an extension to its Regional Compliance Entity. Each entity desiring the extension shall submit a plan and obtain approval from its Regional Compliance Entity within 6 months of approval of this standard. The Regional Compliance entity will review the requests and approve on a case by case basis. Compliance would be required after the date approved by the Regional Compliance Entity.
	Yes
	The use of the term "control center" needs definition and align with that which will be used in the CIP critical asset identification methodology. The terms "primary" and "back up" control center or functionality should also be defined. R1.1 the use of the term "prolonged" is subjective and should be revised to identify a definite period of time. R1.2.4 the actual power supply requirements should go here. BAL-005 R15 regarding back up power supplies should be revised and transplanted to this standard. consider consulting with the BACSDT on moving and enhancing this requirement. R1.3 is vague - "Keeping…consistent" may be redundant to the requirements already listed unless it is intended to mean something else. if so, be specific. R4 & 5 both contain the phrase "during the time when the primary control center functionality and the backup functionality are both available for use". what is the intent of this phrase. Does this mean that the remainder of the requirement does not apply if both are not available for use? Recommend removing this phrase from both requirements. R6.1 should apply only to changes that are related to Reliability Standards or other items specifically identified. Otherwise even very minor changes (such as corporate related features) would be subject to this requirement even though there is no reliability impact. R8. the term "annual" needs better difinition in this standard or within the NREC Standards. Does annual mean every calendar year, or every 12 months? R8.3 should simply state "Test results shall be documented.". Lessons learned, etc are related to corporate and industry practices and are not part of reliability standards, otherwise there would need to be an entire standard for a corrective action process. R9 is not needed. The way this standard is written, there is NO allowable outage time permitted on either the primary or back up control center. As soon as one is unavailable the entity is immediately non-compliant. For an entity to continue to operate in non-compliance would be a significant exposure to penalties. What this standard really needs are requirements that describe the allowable outage time on the primary and back up control centers. The reality is that at some point every entity will need to disable one of their facilities so that maintenance can be conducted (whether it be planned or unplanned). Consider adding provisions for short term planned and unplanned outages on either the primary or back up control center. This would be similar to outage "time clocks" in the nuclear world. This would allow entities to make repairs and upgrades on the primary and back up control centers without automatically being non-compliant when conducting such activities.
	Yes
	Individual
	Kris Manchur
	Manitoba Hydro
	No
	I suggest the applicability for the Transmission Operator be changed to the following: "Transmission Operator operating Bulk Electric System (BES) Facilities at 100 kV or higher, including those Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System." The Transmission Operator that just has a radial connection to the BES is taken care of by the definition of Bulk Electric System which states: "Radial transmission facilities serving only load with one transmission source are generally not included in this definition."
	Yes
	Yes
	Yes
	Yes
	Yes
	No
	Yes

	Individual
	Richard Salgo
	Sierra Pacific Power Co. (dba NV Energy)
	No
	We would recommend the deletion of the last portion of the applicability statement in 4.1.2. The suggestion is to delete "or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)". We believe this part of the applicability is highly subjective and would result in uncertainty among entities who are excluded today, but could suddenly be subject to this Standard due to a subjective judgment call made by their Regional Entity at some point in the future. The Regional Entities presently do not exhibit consistency in their determination of the components of the BES, and quite likely would be even less consistent in a determination of facilities "critical to the reliability of the BES". The applicability statement that would remain after this suggested deletion would not only be clear and objective, it would also point to the specific entities that should be responsible for complying with this Standard.
	Yes
	This is an improvement to the Standard.
	Yes
	The VRF's and Time Horizons appear to be appropriate.
	Yes
	No
	n R2 Lower, we recommend that the VSL language be amended to strike "located in one of its control locations" and replace with "available to Operators at one of either the primary or backup control centers" and in R2 Moderate, amend to remove "located in either of its control locations" and replace with "available to Operators at any of its control locations". In R5, it appears that the degree of severity will be nearly impossible to determine. The VSL language calls for a determination of exactly what percentage of the Reliability Standards can be complied with from the backup center. While we don't have a specific suggestion, we believe that the Auditors will have a very difficult time making a determination with the VSL's as written. In R7, there is only one VSL and it is "severe". The degree of violation here must depend upon the level of dependency that the backup functionality has upon the primary control center and the number and relative importance of the functions for which that dependency exists. We respectfully disagree with the exclusion of Lower, Moderate and High VSL's and the classification of any violation as being "severe" for this Requirement.
	Yes
	In R1.3, a requirement is made to have a process for keeping the backup functionality "consistent" with the primary control center. The word "consistent" will be subject to much interpretation. Backup Control Centers inherently carry somewhat less functionality than the primary centers even though they may satisfy all of the compliance requirements with the Reliability Standards. In R2, we suggest a change in the language to say "…shall have its Operating Plan for backup functionality available to its System Operators at its primary control center…" This would allow for the use of electronic document management, as many entities have moved away from the tedious chore of maintaining hard-copy procedures in their control centers and should not be found non-compliant for using a progressive electronic document management solution. R3: It is unclear what is meant by directing BES operations through other entities, and what would constitute including "provisions for loss of those entities' control functionality". If for example, we direct BES operations through issuing switching instructions to a TO entitity in our balancing area, do we become responsible for the loss of that TO's primary control center under this language? If this is the implication, we believe this Requirement is inappropriate. R4/R5: Why is there a conditional statement present in these Requirements ("…shall, during the time period when the primary control center functionality and the backup functionality are both available for use,…)? This literally states that this Requirement is inactive upon loss of the primary control center. After reading it several times, we continue to be unclear about the intent of that conditional statement. R6: We don't believe it is reasonable to require entitites to update, approve, and keep necessary documentation for minor changes to backup facility plans for items such as "contact information". Phone numbers, fax, cell numbers, etc are all relatively dynamic, and should lie below the threshold of providing full plan updates. Perhaps this update/approval is needed for material changes to the Plan, Process or notification protocols, but minor, insignificant edits should not require this degree of documentation. R7: This specifies that the backup capability shall not depend on the "primary control center" for functionality to maintain compliance with the Standards. This is where much interpretation may arise. Most backup control facilities will have a fully redundant EMS computer, but it may depend on SCADA information that passes through the building which houses the primary control center. Such communications are outside the primary control center, yet in the same facility. Would this situation constitute a "dependency upon the primary control center, and if so, is the intent of this Requirement to expand beyond the confines of the "Primary Control Center" itself? R8.3: We suggest that it is unnecessary to

	document and incorporate into subsequent Plan revisions items that are characterized as "lessons learned". We shoud always be learning from test results and improving plans and processes, but as a compliance requirement, we believe this is onerous. Suggest replacement of the term "lessons learned" with "deficiencies", such that it reads "Test results shall be documented and deficiencies noted and incorporated in subsequent revisions of the Operating Plan for backup functionality".
	Yes
	Yes and No. This Standard has some very positive attributes that will help the industry attain an adequate level of reliability. These include the requirement to establish a Plan and Process for transition to the backup center, the definition of transition time from Primary to Backup center and the requirement to conduct an annual test of the functionality. These are necessary elements to ensure reasonable functionality of the backup plan to continue operations. Where it perhaps goes to far is in the areas of requiring auditable records of updates/approvals for minor and insignificant changes to the Plan, and the prescription of the level of redundancy being unclear and perhaps impossible to comply with depending on the assumptions made about the contingency that causes the backup plan to be executed.
	Individual
	D. Bryan Guy
	Progress Energy Carolinas, Inc.
	Yes
	No
	Transition Period – Different transition period requirements are needed in order to correlate with the various reasons that a primary control center can be lost. A blanket 2-hour requirement forces a backup site to be within approximately 60 - 90 miles of the primary site to cover the scenario of the quick loss ("crater") of the primary center, where offsite personnel must travel from a non-business location to the backup site. However, this distance is insufficient to protect against the loss of both the primary and backup centers due to a major storm, such as a hurricane. Either the transition period needs to be increased to 4 hours, or exceptions are needed for centers located in hurricane-prone areas. Clarification requested as to what consitutes "loss of primary control center functionality" and what constitutes "backup functionality up and running"? Is the functionality to mean at a minimum the aggregate abilities to monitor/maintain frequency, perform AGC, calculate ACE, and perform interchange scheduling (for BA's) and/or for TA's, the minimum aggregate abilities to monitor and control transmission system voltages, power flows, the switching of transmission elements, and ability to respond to IROL's and SOL's violations? Suggest better definition which would identify the minimum as being any one (or all) of the following: -- loss of ability to monitor and provide basic tie line control for maintaining the status of all inter-area schedules, -- loss of ability to monitor and control critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. -- loss of ability to maintain basic voice communication capabilities with other areas.
	Yes
	No
	What is purpose of requiring Operating Plans to be retained for prior 3 years? It should be satisfactory to maintain current active plan with rentention revisons of last full calendar year unless there has been a compliance violation identified by the Regional Compliance entity. R8 – Does a test in January of one year followed by a test in December of the following year meet the requirement of an "annual" test? If not, the wording here should match Violation Security Levels section D.2.R8. M5 – Does this require a document detailing each requirement of all Reliability Standards along with a description of how each is satisfied at the backup (similar to an audit response)? If not, what else can satisfy this measure? M7 – Does this require a document detailing each requirement of all Reliability Standards along with a description of how it is satisfied at the backup (similar to an audit response) without utilizing equipment at the primary? If not, what else can satisfy this measure? D.1.4, 5th bullet (related to M5) – Does this require a demonstration of adequate backup functionality to be repeated and documented at least once between compliance audits? This measure is not needed since R8/M8 requires an annual test with documentation. D.2.R8, Lower Level – States that a violation occurs if subsequent tests occur more than 12 months apart. Section B.R8 states that an annual test shall be conducted. Unless the term "annual" is defined as "every 12 months" in a reference document, these descriptions must match.
	No
	Reference section D.2 Violation Severity Levels R5 -- there are specific percentages stated therein, how are they calculated? Is it per standard or per individual requirement and sub-requirements?
	No
	Effective Date – 24 months is not adequate time to address such a significant change in requirements from EOP-

	008-0. The requirement is changing from a recovery plan to a hot-standby backup available within 2 hours. Additional time is needed to choose a backup methodology, budget accordingly, purchase/construct a backup site (or negotiate with another entity, though the feasibility of this is questionable), design backup voice and data communications, and implement – all per CIP requirements while upgrading existing primary equipment/facilities to meet CIP requirements with implementation schedules through 2010. This requires multi-million dollar actions that must be addressed with a methodologically sound approach to avoid rework and undue financial burden. PEC suggests an implementation period of 1) 36 months for Substantial Progress (i.e. groundbreaking) and 2) 48 months for full implementation.
	Yes
	R5 – Compliance with all Reliability Standards should not be required immediately upon transition to the backup. The focus at immediate transition must be solely upon standards directly-related to essential BES reliability. This is evidenced within this standard by choosing an annual test only lasting 2 hours, which will only verify the basic functionalities of SCADA, alarming, voice & data communications, AGC, state estimator and contingency analysis. The requirement to immediately meet all standards causes undue time/finances to be spent on hot-backup technology for non-essential functions, and thus decreases attention to essential functions. Non-essential standard requirements such as inadvertent/interchange check-outs, TTC/ATC postings, transaction tagging, etc should be identified, and a longer transition requirement specified, such as 48 hours. R7 – How does this apply to a situation where primary EMS or voice communication equipment resides in a facility geographically separate from the primary center's control room? Does the phrase "does not depend on the primary control center" refer to the control room facility only, or does it also apply to the facility housing EMS/voice communication equipment? What distinguishes equipment for compliance to this standard versus CIP-009-1?
	Yes
	Group
	NPCC
	Guy Zito
	NPCC
	No
	The addition of the wording "operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV," is not appropriate.
	Yes
	No
	We agree with the VRFs for R1 to R8 but not R9. We assess the reliability impact of (R9) failure to come up with a plan 6 months after an entity has experienced a loss of its primary control center or backup capability and expects such loss to last for 6 months or more is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower be assigned to this requirement.
	Yes
	We do not agree with some of the requirements (see our comments under Q7) and hence some Measures may need to be revised if the SDT agrees with any of our suggested changes to the requirements.
	No
	(i) R2: It requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guidelines. (ii) R4: The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. (iii) R5: Same comment as in (ii) except the entities are the BAs and applicable TOPs. (iv) R6: There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not review and if necessary update its plan after 18 months, or 120 calendar days after changes were made to the backup capability; a Severe for failing to review and if necessary update its plan for a longer time period or not at all.
	Yes

	Yes
	R3: It stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." We do not agree that this requirement applies to the TOP only. There might well be situations that an RC or a BA directs it operations through other entities as well. We suggest the requirement to also include the RC and the BA by rewording to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations…" R4: We are not sure why the condition: "…during the time period when the primary control center functionality and the backup functionality are both available for use…" is included since having both control center functionalities available for use suffice to meet the condition for: "…have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simply stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed, be eliminated, and include the required clarifications in the Measures Section. R5: Please see our comments on R4. We do not think R5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. R7: We do not see the need for this to be a stand alone requirement. This requirement can be included as one of the sub-requirement in R1, or even combined with R1.3.
	Yes
	Backup functionality for RCs, BAs and applicable TOPs are essential to ensuring continuous reliable operation of the BES. This standard is needed to provide this assurance.
	Group
	Southern Company Transmission
	Roman Carter
	Southern Company Transmission
	Yes
	Yes
	Yes
	Yes
	No
	**For Requirement 5, a cursory review of the applicable BA and TOP standards left uncertainty as to whether some standards pertain to monitoring, control, logging, or alarming actions within the requirements. For example, BAL-005 states that the TOP must be included with the metered boundaries of a BA Area. NERC standard COM-001 states the TOP shall provide adequate and reliable telecommunciations facilities. Unless there is a definite and an agreeable number of standards applicable to the TOP and BA pertaining to monitoring, control, etc., it is difficult to determine whether you exceed the 70/80/90% thresholds associated with Lower, Moderate, or High VSLs. Until there is a predetermined number of applicable standards that can be used as a benchmark for determining the correct level of VSL, it is recommended that only the Severe VSL be utilized along with its current criteria. **For R8, it is recommended that the 3 components contained within the Lower VSL be staged for Lower, Moderate, and High VSL. For example, if an registered entity failed to fulfill one of the components (e.g., testing for less than 2 hours), this would result in a Lower VSL. If a registered entity failed two components (e.g., tested < 2 hours AND it was done in more than 12 calendar months), then this would equate to a Moderate VSL. To fail to meet all three components would equate to a High VSL.
	Yes
	Yes
	**In reference to the Applicability Section 4.1, the following recommendation on the format is suggested: 4.1.2 Transmission Operators that operate Facilities defined below: 4.1.2.1 Facilities operated at 200 kV or above 4.1.2.2 Non-radial Facilities operated at 100 kV 4.1.2.3 Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES) In addition to the format change noted above, there could be a misinterpretation with use of the term 'critical' in this standard considering its significance to CIP-002? We suggest you consider the terms crucial, important, etc. as an alternative word for critical. **With respect to R1.1, an

	Operating Plan should include the location for providing backup functionality. There is a concern with how much specificity is required. If the Operating Plan becomes available to the public, the inclusion of the detailed location of a backup control center may unnecessarily create exposure to CEII information. **Requirement R1.1 does not clarify the meaning of “prolonged period of time.” It is not clear if this means eight days or eight months for example. Should there be some correlation to Requirement R9, which provides that six months is the threshold for notifying the Regional Entity about restoration efforts? **The standard should consistently group sub-requirements under each of the relevant components – Operating Plan, Operating Procedure, and Operating Process. As written, the arrangement is too scattered. Note the order of the requirements and how they are grouped: Requirements R1.1, R1.2, R1.5, and R1.7 correlate to the Operating Plan; Requirements R1.3 and R1.6 correlate to the Operating Process; and Requirement R1.4 correlates to Operating Procedures. The following recommendations ensure more consistency: (a) Insert R1.7 after R1.2 since R1.7 addresses identification of roles for the Operating Plan. It should not be the last item. **R1.5 should be put under R1.6 as a sub-requirement. Also reword the requirement to say The transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running must not exceed two hours. **Under R3, it is unclear as to what the requirement is stating. Are you saying that a registered entity that is relying entirely on other entities to perform the TOP function is also responsible for making sure their Operating Plan provides provisions for the loss of each of the other entities' control functionality? Are there such "Pseudo TOPs" out there that this describes? Clarification would be good for Industry.
	No
	Not in its current form. However, with the changes we have recommended, we believe that it could.
	Individual
	Alice Druffel
	Xcel Energy
	Yes
	Yes
	No
	Data retention should be 3 years.
	Yes
	Yes
	R1.5 Please clarify what you mean by "fully implement" and "get backup functionality up and running". As written, this requirement is too vague. Related to R1.5, please modify M1 to include clarifying language such as "functionality required for maintaining compliance". R1.2.1 Please clarify what is meant by "visualization capabilities". This statement is too vague and leaves too much room for interpretation. R1.3 Please clarify what is meant by "consistent". What processes need to be covered? This requirement is too vague and general, which leaves too much room for interpretation. R1.6 Please clarify/outline what minimum actions are required during the transition period. R1.6.2 To be more clear, we recommend changing "risk" to "impact". R5 As drafted, this requirement implies that both the primary and backup control centers have to be in operation at the same time. This is not practical, as only one control center can communicate with the RTUs. This requirement should be reworded. R6.1 Strike "contact information". This is not necessary to include in the requirement. R8.2 Testing for a minimum of 2 continuous hours is unnecessary and problematic b/c we would lose accounting data which affects our CPS reporting data. A minimum test of 30 minutes is reasonable and sufficient. Please either modify to 30 minutes or provide a factual basis for the 2 hours.
	Yes
	There are some areas of concern that need addressed/ clarified. However, if they are properly addressed, then we feel this standard will help deliver an adequate level of reliability.
	Individual
	Edward J Davis
	Entergy Services, Inc
	No

	We suggest the Applicability to Transmission Operators (4.1.2) be revised as follows to improve readability, to address the ambiguity of the use of the word "critical", and to address section c of the Applicability statement. Use of the term "critical" is vague and causes confusion as evidenced in the Vegetation standards, Cyber standards, and others. We suggest not using "critical" and revising the Applicability to address what is desired - requiring backup functionality for operators of "transmission facilities that have a material impact on the reliability of the BES." We suggest the following Applicability for Transmission Operator: 4.1.2. Transmission Operator operating: a) Transmission Facilities at 200 kV or above, or b) non-radial Transmission Facilities above 100 kV, or c) Transmission Facilities operating at voltages lower that those identified in a) or b) that are demonstrated to have a material impact on the reliability of the Bulk Electric System (BES)
	Yes
	No
	M4 and M5 contain the phrase "shall provide dated evidence that it has demonstrated that it has a (BCC)…" Measures should not include requirements. These measures include new requirements and unspecified additional measures on several unspecified entities. These measures include a requirement that the RC, BA or TOP "demonstrate" BCC functionality to some unspeicifed entity and then that unspecified entity must "provide dated evidence" to the RC, BA and TOP so the RC, BA and TOP can provide that "dated evidence" for evidence of compliance. This requirement for demonstration to, and approval by, some unspecified entity is not in the NERC standards. We suggest the demonstration apsect of these measures be deleted and the measures be changed to: "M4. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility ……." "M5. Each Balancing Authority and applicable Transmission Operator shall provide dated evidence that it's backup functionality …. "
	Yes
	Yes
	The terminology in R1.1 "for a prolonged period of time" is too vague. Please be more specific. The TOP situation indicated in R3 is unclear. What is the arrangement of a TOP directing BES operations through other entities? Is it envisioned that the TOP might be using, say, the RCs control center to run the TOP's BES? Please change the language so the applicability of this requirement is obvious. The rewording of R4 and R5 is confusing. Instead of trying to include all the ideas into one sentence, it would be better and more clear to include a couple of separate sentences. For instance, we suggest for R4, and similar wording for R5: "R4. Each Reliability Coordinator shall have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. This functionality may be provided through its own dedicated backup facility or at another entity's control center. If the loss of the primary or backup capability has already been experienced, a second backup facility is not immediately necessary, i.e., double redundency is not necessary."
	Individual
	Greg Rowland
	Duke Energy
	Yes
	No
	We agree that two hours is appropriate for all applicable entities. However we think more clarity is needed on exactly what is required within two hours. R1.5 should be revised as follows: "A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in R1.2 that is less than or equal to two hours". R1.6 should be revised as follows: "An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in R1.2. The Operating Process shall include, at a minimum:". R8.1 should be revised as follows: "A demonstration of the transition time between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in R1.2".
	Yes
	No

This standard uses the terms "control center", "capability", "facility" and "functionality" somewhat interchangeably. We believe the standard should consistently use the term "functionality" in the Requirements, Measures and Data Retention (see detailed comment #7 below). The Data Retention requirements are onerous and need further review. For example, there is no need to retain three years of old Operating Plans for backup functionality.
No
Once the requirements are revised, the VSLs need to be revisited and cleaned up accordingly. For example, the Lower, Medium and High VSLs for R4 and R5 are unworkable - how can anyone document that the backup functionality includes monitoring, control, logging and alarming sufficient to maintain compliance with 90%,80%, 70% of the applicable requirements of other standards? This would require an impossible burden of recordkeeping. The VSL for R8 imposes a new requirement - that the entity demonstrate through a test that the transition time is less than or equal to two hours.
Yes
Yes
Detailed edits - see revisions in CAPS below: R1 - Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have an Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center FUNCTIONALITY becomes inoperable. This Operating Plan for backup functionality shall include the following at a minimum: R1.1 - The location and method of implementation for providing backup functionality for a prolonged period of time, AS DEFINED BY THE OPERATING PLAN. R1.2.5 - Physical and cyber security. SDT SHOULD DELETE THIS REQUIREMENT SINCE IT IS COVERED IN THE CIP STANDARDS REQUIREMENTS. R1.3 - An Operating Process for keeping the backup functionality consistent with the primary control center FUNCTIONALITY. R3 - Question : What is an entity? More importantly, what is NOT an entity? R4 and R5 - COMBINE THESE TWO REQUIREMENTS INTO ONE AS FOLLOWS: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (such as monitoring, control, logging and alarming) needed to maintain compliance with all applicable Reliability Standards". R6.1 - The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup FUNCTIONALITY AS DEFINED IN R1.2. R7 - Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup FUNCTIONALITY that does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards. R9 - Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of its primary or backup FUNCTIONALITY and that anticipates that the loss of primary or backup FUNCTIONALITY will last for more than six calendar months, shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup FUNCTIONALITY. M1 - Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center FUNCTIONALITY becomes inoperable. M4/M5 - Language needs to match exclusions included in R4/R5. Same clean up as noted in R4/R5 comments above M7 - See comment on R7 above M9 - See comment on R9 above
Yes
It appears that this standard is moving in the right direction.
Group
Electric Reliability Council of Texas, Inc.
Vann Weldon
ERCOT Inc.
Yes
Yes
Yes
No
M5: change “it’s” to “its” M7: delete if R7 is made part of R1 M8: this measure and the related data retention requirement (Bullet 8) imply that testing must occur immediately on changing the Plan. Also change “such testing” to “previous testing” M9: change if R9 is changed Data Retention Bullet 3: this will be hard to do until the standard

	has been in place for several years. It may be deleted if R3 is changed or removed. Data Retention Bullet 6: this will be hard to do until the standard has been in place for several years. Data Retention Bullet 7: delete if R7 is rolled into R1
	Yes
	Yes
	Yes
	R1.2: The word "overview" seems to allow a lot of room and the measure (M1) does, too. However, when it comes to audit time, how specific might the auditor think it needs to be? R3: While ERCOT is the registered Transmission Operator in the region, it does not have direct control over the control facilities of all transmission operators and Qualified Scheduling Entities in ERCOT. ERCOT's Protocols and Operating Guides which require those entities to have and maintain backup facilities. Compliance with those requirements is monitored by ERCOT and the Texas Regional Entity. If ERCOT's Operating Plan would be considered to be in compliance based on references to such Protocol and Operating Guide requirements, rather than detailed provisions for each of the other entities, then this requirement is acceptable. Otherwise, it should be revised to accommodate such a method of compliance. R4 and R5: Is this just a way to say that there is no requirement to have a backup to the backup facility in the event that the primary control center functionality is lost? It also seems to say that when both primary and backup are available, the RC, BA and TO have to also have a Backup Control Center Facility. This requirement needs some simplified wording to make its intent more clear. Maybe using more than one sentence would help. R7: Should be part of R1 R8.3: add “as necessary” between “incorporated” and “in” R9: Why six months to provide something that should be in place all the time?
	Group
	MRO NERC Standards Review Subcommittee
	Joe DePoorter
	MGE
	Yes
	Yes
	Yes
	No
	M1, M2, M3, M6, states that Entites shall have a "dated, current, in force Operating Plan…", The SDT is placing a measurement that is not contained in the Requirement. M4, M5, M7, states that Entites shall provide "dated evidence…", The SDT is placing a measurement that is not contained in the Requirement.
	No
	R1, part of the Lower VSL category of non compliance is "…not dated with evidence of its last issue date.", this is not contained within any part of R1. The VSL Criteria Strawman Document sites that for procedures/programs, in the Lower Category, "The responsible entity has demonstrated the existence of required procedure/program but is missing minor details or minor program/procedural elements. Such deficiencies would not impact the achievement of the objective of the requirement." Recommend that "…not dated with evidence of its last issue date." be deleted from R1's VSL. R4, part of the Lower VSL category of non compliance is "…or the evidence of its demonstration is not dated.", this is not contained within any part of R4. The VSL Criteria Strawman Document sites that for procedures/programs, in the Lower Category, "The responsible entity has demonstrated the existence of required procedure/program but is missing minor details or minor program/procedural elements. Such deficiencies would not impact the achievement of the objective of the requirement." Recommend that "…or the evidence of its demonstration is not dated" be deleted from R4's VSL. R5, part of the Lower VSL category of non compliance is "…or its evidence is not dated.", this is not contained within any part of R5. The VSL Criteria Strawman Document sites that for procedures/programs, in the Lower Category, "The responsible entity has demonstrated the existence of required procedure/program but is missing minor details or minor program/procedural elements. Such deficiencies would not impact the achievement of the objective of the requirement." Recommend that "…or its evidence is not dated" be deleted from R5's VSL. R7, part of the Severe VSL category of non compliance states "…dated evidence shows that…", the word "dated" is not contained within any part of R7. R8, part of the Lower VSL category of non compliance is "…has provided evidence, such as dated records, that it has tested its dated,

	current, in force Operating Plan for backup functionally, with evidence of its last issue, through actual implementation…" If an Entity accomplished this they would BE compliant. Perhaps the SDT forgot to add a deficiency (negative aspect) to a minor detail within the VSL. Overall it seems that the SDT has been directed to place some sort of "date (d)" qualifier within the VSLs. If there is another document that is directing this (i.e., Generally Accepted Government Accounting Standards?), it would be helpful to the Utility Industry of what that document is. VSLs should be a direct reflection of the Requirements.
	Yes
	Yes
	R1, Requires that applicable entities have an Operating Plan covering "backup functionality". Then R1.1 uses "backup functionality" as a sub-requirement to R1, without explaining what "backup functionality" is. Would a Balancing Authority's backup functionality be all NERC requirements assigned to a Balancing Authority? Please define. R1.5, What happens if the applicable entity needs more than two hours to get "backup functionality" running? R1.6.2, Does "…as well as during outages of the primary/backup functionally" include SCADA, Energy Managements Sysyems, ect, updates? Could the SDT clarify the maximum amount of time that updates, patches, maintenance could take place without harming the BES, such as within one hour? R2, states the Operating Plan is required to be " at the location supporting backup functionally". If this is the backup control center, the MRO agrees, if not please clarify. R4, The MRO believes this requirement is redundent and should be removed. The MRO believes that this requirement would put the RC in double jeopardy. Please clarify why R4 is written. R5, The MRO believes this requirement is redundent and should be removed. The MRO believes that this requirement would put the BA & TOP in double jeopardy. Please clarify why R5 is written.
	Yes
	The MRO commends the SDT. The SDT has incorporated many past comments and given great replies to the many questions, Thank you.
	Group
	ITC
	Debra Yinger
	International Transmission Company
	No
	The addition to 4.1.2 attempts to address what is really a registration and BES defintion issue. This is not the proper place to these issues. The applicability should be just to the TOP and any limitation to the scope of the TOP should be handled in registration.
	Yes
	No
	Per comments made elsewhere, requirement 6 should be part of requirement 1 and therefore have a Medium VRF.
	No
	Suggest replacing the words "current, in-force" with "approved" for clarity in several of the Measures. The implication of "approved" is that an auditor would be able to see a signature of approval of the Plan. Measure 7 evidence would not be easy to provide since you trying to prove a negative - that you don't do something. An auditor could not practically verify that the technical backup capability does not depend on the primary control center. Per comments elsewhere, the associated requirement should be removed and defer to requirement 1.
	No
	The VSLs for Requirement 3 don't make any sense. Per comments elsewhere, this requirement should be re-written to focus on delegated functions. It is unlikely multiple entities would be involved as implied in the VSLs. For requirement 4 and 5, the VSL would be nearly impossible to calculate or measure from a practical standpoint. The VSL should not be focussed on the number of other Standards that would be violated, but on the Plan itself or the functions. For requirement 7, the only VSL (severe) does not make any sense, further evidence that the requirement itself is not appropriate, as commented elsewhere. For requirement 8, the drafting team should develop VSLs for all levels, similar to requirement 1.
	Yes
	Yes
	Requirement 3 should be re-worded to "Each applicable Transmission Operator "delegating" BES "operational functions to" other entities… At any given time, the TOP may 'direct' any connected GOP or LSE to take an action

	to support BES operations. As written, this requirement could be interpreted to require the TOP to have the backup plan for all connected GOPs, LSEs, etc. incorporated into their plan. Limiting the scope to those functions which are formally delegated is more appropriate and reasonable. Requirement 4 and 5 should be reworded. The requirement is cumbersome to read and understand. We believe the intent of the phrase "during the time period when the primary control center functionality and the backup functionality are both available for use" is intended to clarify that if you are already at your backup, you are not required to have a second N-2 backup. We suggest you add a sub-requirement that clearly states this exclusion and remove the phrase from the main requirement. Requirement 6 should be a sub-requirement of requirement 1 and requirement 6 and 6.1 should be combined into a single requirement that says the plan must be updated annually OR within 60 days of any significant changes. Requirement 7 is unncessary and ambiguos. Requirement 1 adequately addresses the specific requirements of the Plan. Requirement 9 should be modified. If extended operation from a backup facility is a real concern to reliability, the RE should not be waiting 6 months to know there is an alternative plan. If it's OK to wait 6 months, this requirement should be removed.
	Yes
	Individual
	Paul Rocha
	CenterPoint Energy
	No
	CenterPoint Energy believes the applicability should not include the vague, fill-in-the-blank provision of "…or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System." This provision leaves it open to the whim of a Regional Entity to conjure some rationale to "demonstrate", by whatever means, that these requirements should apply to an otherwise exempt entity. Adding to the vagueness of the language is that it is not clear to whom the Regional Entity would make such a "demonstration". If the Regional Entity "demonstrates" the alleged criticality to itself, the problems with the proposed language should be self-evident to even the most naïve proponent. Even if the "demonstration" is to an independent, competent, and trustworthy third party (all of which cannot be assumed without specificity of who the independent third party would be), it is unclear what due process is afforded to otherwise exempt entities to argue the facts asserted by the Regional Entity and to argue the reasonabless of the vague, undefined "demonstration" criteria used by the Regional Entity to make its assertion of criticality to the reliability of the BES. CenterPoint Energy recommends that this vague, fill-in-the-blank provision be deleted.
	No
	CenterPoint Energy believes this standard will likely deliver a more than adequate level of reliability. Some might argue that more than adequate reliability is always good. However, CenterPoint Energy disagrees with a one-sided view that ignores cost considerations. If more than adequate reliability can be delivered for minimal cost, then such a level of reliability is certainly in the public interest. However, if more than adequate reliability comes at a significant cost, then a balanced view that weighs costs and benefits would better serve the public interest. Specifically, CenterPoint Energy believes R1.3 is unnecessary and could have unintended consequences. R1.2 outlines the requisite backup functionality, rendering R1.3 unnecessary. Given the infrequency with which loss of primary control center functionality occurs (due to the redundancy and hardening of such facilities), it is unnecessary and probably not cost-effective for backup control center functionality to be consistent with the primary control center. Some reduced backup functionality, that still meets the requirements of R1.2, is probably the most cost-effective approach in most circumstances to ensure adequate reliability in the infrequenct circumstance of the loss of primary control center functionality. Furthermore, R1.3 could have the unintended consequence of entities choosing not to voluntarily exceed the minimum required functionality of the primary control center because R1.3 essentially doubles the cost of any discretionary upgrade to the primary control by mandating that the backup facility maintain the same discretionary functionality. Moreover, the primary control center may have functionality unrelated to reliability considerations, such as market-related functionality, that arguably would need to be provided by the backup control center under R1.3. Backup functionality unrelated to reliabilty considerations should not be mandated by reliability standards but instead should be left to individual entities and their market stakeholders to decide. For all these reasons, CenterPoint Energy believes R1.3 should be deleted. Furthermore, CenterPoint Energy recommends that the SDT consider modifying R4 and R5 to specifiy that backup functionality be sufficient to comply with all medium or higher VRF requirements. Again, given the

	infrequency of loss of primary control center events, the most cost-effective approach to ensure an adequate level of reliability for backup control center functionality is probably to not require the lower VRFs to be maintained in such rare circumstances. When considering this recommendation, it might be helpful to remember that control centers operated reliably for years before the version 0 and beyond NERC standards without all the functionality now available and now required by NERC standards. Generally, such reliability was accomplished through more conservative operation. More conservative operation has costs usually in terms of inefficient generation dispatch. However, an entity may find that rare instances of inefficient generation dispatch due to conservative operation by a backup facility might be less costly than the on-going costs to retain full backup capability to meet all the NERC requirements, even the lower VRF requirements.
	Individual
	Greg Ward / Darryl Curtis
	Oncor Electric Delivery
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	No
	Yes
	Individual
	Robert Temple
	Western Area Power Administration
	No
	Please define radial/non-radial; Is the definition radial to load, radial to generation, radial to both load and generation?
	Yes
	Yes
	No
	These measures should be consistent with other existing data retention measures that have already been approved (3 years worth of data). Suggestion is to have the current year and two previous years worth of data.
	No
	Suggestion is to apply percentage levels to requirements as opposed to percentage levels to standards (as this is currently written).
	Yes
	Yes
	Requirement #1.6.2; Change "Actions to manage the risk…" to "Actions to manage the impact…" Requirement #3; Please specify the meaning of "…directing BES operations through other entities…" What does through other

	entities mean? Requirement #5; "during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality…" This statement is very vague and implies having two control centers in operation at all times. This sentence needs to be rewritten. Requirement #5; "maintaining compliance with all Reliability Standards…" is too vague. Please specify the Reliability Standards required for compliance. Requirement#6.1; Timing on an updated Operating Plan is vague. A suggestion is to state the updated Operating Plan should be within 12 months from the last update. Requirement #8.3; Lessons learned should not be included in the Operating Plan. A suggestion is to have the lessons learned as evidence resulting from the tests.
	No
	Without understanding the implications regarding some of the vague wording on this draft, constructive comments cannot be provided.
	Individual
	Kathleen Goodman
	ISO New England Inc
	No
	We agree with the drafting team's intent to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV by limiting TOP applicability. However, this is a registration issue and really identifies an issue with the definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration. TOPs operating only radial transmission lines serving load are already excluded from registering per Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Limiting applicability further than this on radial transmission lines in essence redefines the BES and that is not a function of a standard. Please remove the language limiting the applicability.
	Yes
	No
	We agree with the VRFs for R1 to R8 but not R9. We assess the reliability impact of (R9) failure to come up with a plan 6 months after an entity has experienced a loss of its primary control center or backup capability and expects such loss to last for 6 months or more is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower be assigned to this requirement.
	No
	We do not agree with some of the requirements (see our comments under Q7) and hence some Measures may need to be revised if the SDT agrees with any of our suggested changes to the requirements.
	No
	(i) R2: It requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guidelines. (ii) R4: The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. (iii) R5: Same comment as in (ii) except the entities are the BAs and applicable TOPs. (iv) R6: There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not review and if necessary update its plan after 18 months, or 120 calendar days after changes were made to the backup capability; a Severe for failing to review and if necessary update its plan for a longer time period or not at all.
	Yes
	Yes
	R3: It stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." We do not agree that this requirement applies to the TOP only. There might well be situations that an RC or a BA directs it operations through other entities as well. We suggest the requirement to also include the RC and the BA by rewording to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations…" R4: We are not sure why the condition: "…during the time period when the primary control center functionality and the backup functionality are both available for use…" is included since having both control

	center functionalities available for use suffice to meet the condition for: "…have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simply stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed. R5: Please see our comments on R4. We do not think R5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. R7: We do not see the need for this to be a stand alone requirement. This requirement can be included as one of the sub-requirement in R1, or even combined with R1.3.
	Yes
	Backup functionality for RCs, BAs and applicable TOPs are essential to ensuring continuous reliable operation of the BES. This standard is needed to provide this assurance.
	Individual
	Dan Rochester
	Independent Electricity System Operator
	Yes
	Yes
	Yes
	We agree with the VRFs for R1 to R8 but not R9. We assess the reliability impact of (R9) - that failure to come up with a plan 6 months after an entity has experienced a loss of its primary control centre or backup capability and expects such loss to last for 6 months or more - is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower VRF be assigned to this requirement.
	Yes
	We do not agree with some of the requirements (see our comments under Q7) and hence some Measures may need to be revised if the SDT agrees with any of our suggested changes to the requirements.
	No
	(i) R2: It requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirment is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guideline. (ii) R4: The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. (iii) R5: Same comment as in (ii) except the entities are the BAs and applicable TOPs. (iv) R6: There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not update its plan after 18 months or 120 calendar days after changes were made to the backup capability; a Severe VSL may be assigned for failing to update its plan for a longer time period or at all.
	Yes
	Yes
	R3: We have two comments on this Requirement: a. It stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." We do not agree that this requirement applies to the TOP only. There might well be situations that an RC or a BA directs its operations through other entities as well. We suggest the requirement to also include the RC and the BA by rewording to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations…" b. We believe the wording is ambiguous in that in some areas/jurisdictions, there are multiple TOPs that one of them direct the operations of the other. For example, an ISO is registered as a TOP while a transmission entity (an owner, for example) within the ISO footprint is also registered as a TOP. The two TOPs perform distinctly different tasks and may even have their tasks and responsibilities clearly stipulated in an agreement, market rule or regional reliability plan. The ISO-TOP directs operations of the transmission-entity-TOP while the latter may be solely responsible for switching operations and maintenance. Both need to have backup capability. The way R3 is worded can be interpreted that

	the ISO-TOP needs to be responsible for the backup capability of the transmission-entity-TOP. We do not believe this is the intent of R3, and this is not acceptable. To clarify this situation, we suggest R3 to be reworded to: Each applicable Transmission Operator delegating its tasks for BES operations to other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality. In other words, this requirement only applies to a TOP if it delegates it task (for which it is still fully responsible) to another entity. R4: We are not sure why the condition: "…during the time period when the primary control center functionality and the backup functionality are both available for use…" is included since having both control centre functionality available for use suffice to meet the condition for: "…have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simple stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed. R5: Please see our comments on R4. We do not think R5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. R7: We do not see the need for this to be a stand alone requirement. This requirement can be included as one of the sub-requirement in R1, or even combined with R1.3.
	Yes
	Backup functionality for RCs, BAs and applicable TOPs is essential to ensuring continuous and reliable operation of the BES. This standard is needed to provide this assurance.
	Individual
	Marty Berland
	Progress Energy-Florida
	Yes
	No
	Transition Period – Different transition period requirements are needed in order to correlate with the various reasons that a primary control center can be lost. A blanket 2-hour requirement forces a backup site to be within approximately 60 - 90 miles of the primary site to cover the scenario of the quick loss ("crater") of the primary center, where offsite personnel must travel from a non-business location to the backup site. However, this distance is insufficient to protect against the loss of both the primary and backup centers due to a major storm, such as a hurricane. Either the transition period needs to be increased to 4 hours, or exceptions are needed for centers located in hurricane-prone areas. Clarification requested as to what consitutes "loss of primary control center functionality" and what constitutes "backup functionality up and running"? Is the functionality to mean at a minimum the aggregate abilities to monitor/maintain frequency, perform AGC, calculate ACE, and perform interchange scheduling (for BA's) and/or for TO's, the minimum aggregate abilities to monitor and control transmission system voltages, power flows, the switching of transmission elements, and ability to respond to IROLs and SOLs violations? Suggest better definition which would identify the minimum as being any one (or all) of the following: -- loss of ability to monitor and provide basic tie line control for maintaining the status of all inter-area schedules, -- loss of ability to monitor and control critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. -- loss of ability to maintain basic voice communication capabilities with other areas.
	Yes
	No
	What is purpose of requiring Operating Plans to be retained for prior 3 years? It should be satisfactory to maintain current active plan with rentention revisons of last full calendar year unless there has been a compliance violation identified by the Regional Compliance entity. R8 – Does a test in January of one year followed by a test in December of the following year meet the requirement of an "annual" test? If not, the wording here should match Violation Security Levels section D.2.R8. M5 – Does this require a document detailing each requirement of all Reliability Standards along with a description of how each is satisfied at the backup (similar to an audit response)? If not, what else can satisfy this measure? M7 – Does this require a document detailing each requirement of all Reliability Standards along with a description of how it is satisfied at the backup (similar to an audit response) without utilizing equipment at the primary? If not, what else can satisfy this measure? D.1.4, 5th bullet (related to M5) – Does this require a demonstration of adequate backup functionality to be repeated and documented at least once between compliance audits? This measure is not needed since R8/M8 requires an annual test with documentation. D.2.R8, Lower Level – States that a violation occurs if subsequent tests occur more than 12 months apart. Section B.R8 states that an annual test shall be conducted. Unless the term "annual" is defined as "every 12 months" in a reference document, these descriptions must match.
	No

	Reference section D.2 Violation Severity Levels R5 -- there are specific percentages stated therein, how are they calculated? Is it per standard or per individual requirement and sub-requirements?
	No
	Effective Date – 24 months is not adequate time to address such a significant change in requirements from EOP-008-0. The requirement is changing from a recovery plan to a hot-standby backup available within 2 hours. Additional time is needed to choose a backup methodology, budget accordingly, purchase/construct a backup site (or negotiate with another entity, though the feasibility of this is questionable), design backup voice and data communications, and implement – all per CIP requirements while upgrading existing primary equipment/facilities to meet CIP requirements with implementation schedules through 2010. This requires multi-million dollar actions that must be addressed with a methodologically sound approach to avoid rework and undue financial burden. PEF suggests an implementation period of 1) 36 months for Substantial Progress (i.e. groundbreaking) and 2) 48 months for full implementation.
	Yes
	R5 – Compliance with all Reliability Standards should not be required immediately upon transition to the backup. The focus at immediate transition must be solely upon standards directly-related to essential BES reliability. This is evidenced within this standard by choosing an annual test only lasting 2 hours, which will only verify the basic functionalities of SCADA, alarming, voice & data communications, AGC, state estimator and contingency analysis. The requirement to immediately meet all standards causes undue time/finances to be spent on hot-backup technology for non-essential functions, and thus decreases attention to essential functions. Non-essential standard requirements such as inadvertent/interchange check-outs, TTC/ATC postings, transaction tagging, etc should be identified, and a longer transition requirement specified, such as 48 hours. R7 – How does this apply to a situation where primary EMS or voice communication equipment resides in a facility geographically separate from the primary center's control room? Does the phrase "does not depend on the primary control center" refer to the control room facility only, or does it also apply to the facility housing EMS/voice communication equipment? What distinguishes equipment for compliance to this standard versus CIP-009-1?
	Yes
	Group
	Pepco Holdings, Inc. - Affiliates
	Richard Kafka
	Pepco Holdings, Inc.
	Yes
	Yes
	Yes
	Yes
	No
	R2 - need to recognize there may be more than one backup facility - wording implies one primary facility and one backup facility. R3 has increments on number of entities rather than number of BES facilities. Concentrating on entities does not address the real issue. R4 and R5 concentrate on percentage of standards met by relying on backup facility rather than number of facilities still under monitoring and control.
	Yes
	Yes
	The requirements should be modified to recognize that duplicate and separate EMS facilities running in parallel without dependence on each other fulfill the need for backup facilities.
	Yes
	Operative word is -help- see previous comments
	Group
	Santee Cooper

	Terry L. Blackwell
	South Carolina Public Service Authority
	No
	In 4.1.2 (Applicability) it is not clear that it is for a radial connection to the BES under 200 kV. There could be differences in what a regional entity deems critical to the reliability of the BES and what a TOP deems critical to the reliability of the BES. Would this allow a Regional Entity to require a TOP with radial facilities deemed critical by the RE to have a backup control center? Suggestion for rewording of 4.1.2: Transmission Operator …. or radial facilities under 200 kV demonstrated by the Regional Entity to be critical to the reliability of the BES.
	No
	We recommend that R1.5 be changed such that the backup plan be implemented in less than two hours and the backup functionality up and running that is less than three hours. Smaller entities that need a larger physical separation between control centers will need at least three hours to get backup functionality up and running.
	Yes
	Yes
	Yes
	Yes
	No
	No
	We believe with our comments from above included in the standard, that this standard will help deliver an adequate level of reliability.
	Individual
	Rao Somayajula
	ReliabilityFirst Corporation
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	In R1.3, I am not sure what "Operating Process" means. I am thinking may be you can say "Back-up Control Facility Opearting guide". Also suggest replacing "backup funtioanlity" with "backup contro funtionality". I feel this conveys the intent better.
	Yes
	Group
	Bonneville Power Administration

	Denise Koehn
	Transmission Reliability Program
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	No
	Yes
	Individual
	David Carpenter
	Brazos Electric Power Cooperative, Inc.
	No
	This new definition basically brings in all TO's that operate transmission lines 100 kV and above given the NERC defintion of a Transmission Operator (The entity responsible for the reliability of its 'local' transmission system…) and the emphasis now on Facilities. This new applicability is much broader than the original version and does not eliminate any burden on TO's, it could in fact be quite the opposite. The new applicability does not seem to match the intent of the old language. Taken literally this means that almost all TO's in ERCOT must have a backup control center. In the past we viewed this Standard applied to ERCOT, the one who directs the operation of the BES, not just a 'local' area. If the intent is to require more TO's to have backup control centers we are against this new concept because of the very small probability of ever losing the primary control center. As this happens so infrequently we feel it is not in the best interest of the electric customers to provide something that will have little benefit or any benefit ever. However, if this standard can be assigned to an entity such as ERCOT by each TO to which this applies then we can accept that concept but not all the new language. The last part of 4.1.2 is ambiguous in several ways. How are Facilities 'demonstrated' to be Critical and to whom and under what criteria? This language is not well thought out. The old 4.1.2, while not great, was better than the new one. The use of the word 'control' leads us to believe that the TO who has the final authority or 'control' of the facilities (small 'f', not capital 'F' for facilities), should have the backup control center and thus we assumed this to be ERCOT. We see no reason for this to change.
	No
	It seems excessive to retain each and every change to these documents and to note that they be 'an approved' plan. We think more emphasis should be placed on having the backup and demonstrating its readiness instead of worrying about documenting everything. No real suggestion for improvement other than to remove some of the unnecessary documentation burdens and language. Perhaps just delete all the lower risk items.
	Yes
	No
	We believe this standard to be excessive if the intent is as stated above to have all TO's have a backup control

	center.
	Individual
	Greg Mason
	Dynegy
	Yes
	Yes
	Yes
	No
	Yes
	Individual
	Roger Champagne
	Hydro-Québec TransÉnergie (HQT)
	No
	The addition of the wording "operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV," is not appropriate and should be removed.
	No
	In the previous version of the Standards, the TOP and BA had a leeway for interim provisions to be included in the plan when extenuating circumstances cause the transition to take longer than two hours (See R8.1 and R8.2 in the redline version). HQT asked to have a similar leeway for the RC. In the curent version, that leeway has been removed for all of them. In the answers provided by the SDT, it seems that they assume that facilities for the RC are in another location than that of the BA and TOP. While this might be true for others, for HQT they are all in the same location. HQT propose that that a bullet be added in R1.6.3 that reads: "Interim provisions must be included in the plan when extenuating circumstances cause the transition to take longer than two hours for the RC, TOP and BA"
	No
	We agree with the VRFs for R1 to R8 but not R9. We assess the reliability impact of (R9) failure to come up with a plan 6 months after an entity has experienced a loss of its primary control center or backup capability and expects such loss to last for 6 months or more is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower be assigned to this requirement.
	No
	We do not agree with some of the requirements (see our comments under Q7) and hence some Measures may need to be revised if the SDT agrees with any of our suggested changes to the requirements.
	No
	(i) R2: It requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guidelines. (ii) R4: The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. (iii) R5: Same comment as in (ii) except the entities are the BAs and applicable TOPs. (iv) R6: There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not review and if necessary update its plan after 18 months,

	or 120 calendar days after changes were made to the backup capability; a Severe for failing to review and if necessary update its plan for a longer time period or not at all.
	Yes
	Yes
	R3: It stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." We do not agree that this requirement applies to the TOP only. There might well be situations that an RC or a BA directs it operations through other entities as well. We suggest the requirement to also include the RC and the BA by rewording to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations…" R4: We are not sure why the condition: "…during the time period when the primary control center functionality and the backup functionality are both available for use…" is included since having both control center functionalities available for use suffice to meet the condition for: "…have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simply stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed, be eliminated, and include the required clarifications in the Measures Section. R5: Please see our comments on R4. We do not think R5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. R7: We do not see the need for this to be a stand alone requirement. This requirement can be included as one of the sub-requirement in R1, or even combined with R1.3. In regard to R7, we would appreciate the SDT to indicate if the EMS system should be doubled also at the Backup facility since R7 specifies that the Backup "does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards.".
	Yes
	Group
	PJM Interconnection
	Tom Moleski
	PJM Interconnection
	No
	In 4.1.2, the SDT creates a new class of TOP. This is beyond the Scope of the Standard. 4.1.2 can only apply to current functional entities.
	No
	The transition timeframe should be defined and justified by the respondant, and be made part of their Operating Plan.
	Yes
	No
	Changes need to be made to address the primary/backup language (see 7 below). Additionally, data retention requirements are far too voluminous. There should only be one version (current) in the Control Center. Requiring 3 years worth of outdated plans in the control room, accessible to the operators, may result in mis-operations.
	No
	Changes need to be made to address the primary/backup language (see 7 below)
	Yes
	No
	PJM's concerns center on the basic premise of the standard; that there is one "primary" facility, and one "backup" facility. With the completion of our Business Continuity plan, PJM will be operated simultaneously from our existing control center, and another fully staffed, redundant center at a remote location (neither facility will be designated "primary" or "backup"). In the event of the loss of one of these facilities, this type of operation will accommodate an instantaneous transfer of all control to the redundant center. For this reason, PJM would like to propose the following addition to the applicability section of the standard 4.2. EOP-008-1 shall not apply to Reliability Coordinators, Transmission Owners, or Balancing Authorities that operate two equal, real-time facilities, at

	geographically diverse sites, either of which is capable of operating as a stand alone, fully functional data center and control center. PJM feels that this type of redundant operation goes far beyond the requirements in the current standard, to ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable. The very narrow exemption provided in the proposed addition is the cleanest. simplest way to accommodate this scenario If the SDT does not agree to the proposed addition to the applicability section, PJM's representative will deliver a redline version of the current draft of the standard to the group at their next meeting. This will have a requirement by requirement, measure by measure, list of all the changes that allow for this type of redundant operation to meet all compliance scrutiny. A copy of this document has been forwarded to Ed Dobrowlski of the NERC office. Beyond this PJM submits the following for consideration: In Applicability 4.1.2, the SDT creates a new class of TOP. This is beyond the Scope of the Standard. 4.1.2 can only apply to current registered entities. PJM would like to strike "allow visualization capabilities that" in R1.2.1. Tools for visualization are not in the requirements for any primary control center. Seems inappropriate to be in the requirements for a backup. Suggest changing R1.2.5 to read "All applicable NERC CIP Standards Suggest adding "unless this change is functionally transparent to the users" to the end of R1.6.1. PJM is aware of several Local Control Centers that have telephone & data switching that is done by a central station. No contact information changes, and the caller should be indifferent to the physical location of the receiver. R3 would require TOPs directing BES operations through other entities to be accountable for the compliance of all of these entities. If this is the intent of the SDT, the Applicability section of the standard needs to be modified to include Transmission Owners (TOs) in lieu of defining other applicable entities in R3. In R5, Monitoring, control, logging, and alarming should all be sub-bullets of R5 (as done in R1.6 "Process shall include"
	No
	No, not as currently drafted. These comments are extensive, and address nearly every requirement and measure. A thorough re-write of the Standard will be necessary before this can go to ballot.
	Individual
	Thad Ness
	AEP
	No
	"Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)" needs to be clearly defined. Each regional entity must have a documented process for defining critical facilities.
	Yes
	The extended transition period increases the criticality of R1.6.
	Yes
	Yes
	Yes
	Yes
	No
	Yes
	The two hour requirement (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) is a more attainable goal. The transition period is addressed in R1.6. With the extended transition period, R1.6 could be expanded to address reliability concerns during the transition.
	Individual
	Jeff Hackman
	Ameren
	No
	We agree with the drafting team's intent to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV by limiting TOP applicability. However, this is a registration issue and really identifies an issue with the definition definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be

	handled in registration. TOPs operating only radial transmission lines serving load are already excluded from registering per Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Limiting applicability further than this on radial transmission lines in essence redefines the BES and that is not a function of a standard. Please remove the language limiting the applicability.
	Yes
	No
	R7 should be a sub-requirement of R1. Thus, it should not have a VRF. The VRF for R8 should be lower. Given that the Operating Plan needs to be tested more frequently than annually to ensure that the backup capability is available when it is needed, this requirement is clearly intended to be administrative. Requirement 9 should be removed from the standard. This is, in essence, is a requirement for an N-2 contingency. It is such a rare occurrence to operate from a backup center for an extended period of time that this requirement is not needed. If the RC, TOP or BA must operate from their backup center or utilizing their backup capability for an extended period of time, they should work with NERC and the Regional Entity to address the specific situation rather than having a requirement that dictates a time frame.
	No
	Measures 1, 2, 3, 6, and 8 require dated, current, in force Operating Plan but there is no time requirement in the associated requirements. Measures should not add to the requirements. What does current really mean? How would the compliance auditor know if the Operating Plan is current given that the requirement does not mention date or time? We suggest removing the term in force because it does not add anything to the requirement. Why would the responsible entity supply an Operating Plan to the compliance auditor that wasn't in force? Measures 1, 2, 3, 6, and 8 also state that evidence of the last issue of the Operating Plan is required. There is nothing in the associated requirements about issuing. Thus again the measures are adding to the requirements but should not. To who is the Operating Plan required to be issued in the Measures? Part of the issue with Measure 6 is that its associated requirement really should be a sub-requirement of requirement 1. This would solve some of the issues with Measure 1. A large part of the issue with Measures 2, 3, 6, and 8 appear to be overuse of copy and paste. The only requirement associated with these measurements that really needs a dated Operating plan as evidence is requirement 1 but as the requirement is currently written it does not require the Operating Plan to have a date. Measure 7 should not include a requirement for dated evidence. What is really needed is that the Operating Plan evidence presented should have a date and the Operating Plan should be verified to not depend on the primary control center. The compliance auditors could not practically verify that the backup capability or backup control center does not depend on the primary control center. Thus, the requirement associated with Measure 7 is really a sub-requirement of requirement 1. Measurement 9 should not require the RC, BA, and TOP to have evidence that a plan has been submitted to its Regional Entity when it loses its primary control center or backup capability or backup control center because the Regional Entity is the Compliance Enforcement Authority. The Regional Entity will know when the plan is received.
	No
	Guideline 3 of FERC's order conditionally approving VSLs for the original 83 regulatory approved standards stipulates that the VSL should not add to the requirement. The Lower VSL of R1 does add a requirement for the document to be dated which violates Guideline 3. Requirement 1 fits the multi-component category of the VSL Guidelines. This category puts the number of sub-requirements that are missing from the Operating Plan into quartiles. Thus, the Lower VSL would be missing one or two sub-requirements the Moderate VSL would be missing three or four sub-requirements the High VSL would be missing five to six sub-requirements and the Severe VSL would be missing seven sub-requirements or the plan would not exist. The VSLs for Requirement 2 should use the term back-up capability along with primary control center for consistency with the requirements. We agree with these levels. The VSLs for Requirement 3 really don't make any sense. It implies there may be more than one other entity that a TOP is directing BES operations through. We don't think that this is likely. Additionally, the VSLs as written do not seem to fit any category within the VSL guidelines document. Why would the VSLs not be divided into quartiles? For the requirement 4, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities forseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the BA or TOP has a backup capability plan, isn't the BA or TOP still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? For the requirement 5, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities forseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the RC has a backup control center, isn't the RC still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? Perhaps the drafting team should consider applying VSLs based on if monitoring, control, logging and alarming are included

	in the backup capability. In its order approving VSLs, the FERC stated in paragraph 27 that they prefer gradated VSLs whenever possible. For requirement 6, we believe a VSL could be written for each severity level using the time requirements established. For instance, high could apply to 18 months and severe to 21 months. Additionally, the VSLs for requirement 6 violation FERC's guideline 3 by requiring the Operating Plan to be dated. The associated requirement does not mention dating. For requirement 7, the only VSL does not make any sense. The VSL implies that the responsible entity may provide evidence that backup plan depends on the primary control center. Why would the responsible entity providing evidence of non-compliance be a severity level? The purpose of providing evidence is to demonstrate compliance. Is this requirement 7 even needed? There are requirements in this standard that require a backup plan. The responsible entity is responsible to comply with this standard and with all other standards even when operating with the backup plan. Can they comply with other standards if the backup plan depends on the primary control center and the primary control center is destroyed? No. Thus, they would violate many other standards. Thus, requirement 7 is implied and not needed explicitly as a requirement. For requirement 8, we do not support a mandatory testing time of two hours or a transition time of two hours. However, considering the requirement as written, we suggest the drafting team could develop VSLs for all levels. VSLs could be written as: Lower: Tested the back plan for less than 30 minutes or The transition time was more than two hours but less than or equal to 3 hours or the test results and lessons learned were not incorporated in subsequent revisions. Moderat: Tested the backup plan for 30 minutes or more but less than one hour The transition time was more than three hours but less than or equal to four hours. High: Tested the back plan for one hour or more but less than 90 minutes or The transition time was more than four hours but less than or equal to five hours. Severe: Tested the back plan for 90 minutes or more but less than two hours or The transition time was more than five hours. For requirement 9, the VSL perpetuates some of the problems that are currently occuring with compliance monitoring of requirements that have periodic reporting requirements to the Regional Entity. The Regional Entity either already has the evidence or a violation has occurred because the report was not submitted on time. The responsible entity should not have to redemonstrate to the compliance auditor that it submitted the plan to the Regional Entity since the compliance auditor is the Regional Entity.
	Yes
	Yes
	Requirement 2 is not needed. What is important is that the plan gets implemented when needed not that some compliance auditor can verify there is a copy of the plan at the backup and primary control centers. Most entities are going to have their plans at the primary and backup control centers to allow them to implement the plan. If they don't, they likely won't be able to implement their plan in the required time frame. Thus, they will already be violating another requirement so lets not provide an opportunity for double jeopary. Requirement 4 should strike "that provides functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator". The RC is already required to comply with these standards regardless of whether they operate from the backup center or the primary center. Requirement 5 should strike "sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority or Transmission Operatore respectively". The BA and TOP are already required to comply with these standards regardless of whether they operate from the location of their backup capability or the primary center. Further, we urge the drafting team to consider combining requirements 4 and 5 to require full backup control centers for the TOP and BA as well as the RC. Requirement 5 is already stringent enough that a backup control center is likely required anyway. Combining the requirements just simplifies the standards. Requirement 6 is really a sub-requirement of requirement 1. Sub-requirement 6.1 is confusing. Because it is a sub-requirement, it must apply to requirement 6. Thus, it would seem that the sub-requirement is requiring the annual review and approval to occur withing 60 days of any changes. What if there are multiple changes in the year? From this perspective, it appears that the sub-requirement is intended to reflect that changes can occur at any time. To clarify the requirement, we suggest the following language as a sub-requirement of R1 along with striking requirement 6 and 6.1: "Each RC, BA an TOP shall review and approve its Operating Plan for backup functionality annually and within sixty calendar days of any changes to the backup location, capabilities or contact information, modify the Operating Plan to reflect the changes." Requirement 7 is unncessary as an explicit requirement. Each RC, TOP and BA is required to comply with all applicable requirements even if they are operating from the location of their backup functionality or backup control center. If their backup functionality relies on the primary control center, the RC, TOP and BA will be unable to comply with numerous other requirements in the event that they lose the functionality of their primary control center. Requirement 8 is not needed and does not accomplish the goal of ensuring the backup capability is available when needed. In reality, an RC, TOP and BA will have to operate utilizing backup functionality significantly more often than annually to ensure that backup functionality is available when needed. In fact, most RC, TOP, and BA already test their backup capability more often than annually even though the current requirement is for an annual test. They do this not because of the testing requirement but because of the need to continue to comply with other applicable requirements. If the other standards requirements already drive the entities to exceed this requirement, why is it needed? It is not. Requirement 9 should be struck. This requirement essentially represents an N-2 condition. The requirements should not try to anticipate extreme conditions such as this. Because RC, TOP and BA are still required to comply with the requirements even if they lose one of the operating centers or backup capability, the RC, TOP and BA will have to make plans to operate in the event of the

	failure of their last operable control center. Thus, failure to begin developing a plan to replace the backup capability or primary control center will surely result in a violation of another requirement (actually likely many requirements).
	No
	With suggested changes.
	Group
	FirstEnergy Corp.
	Doug Hohlbaugh
	FirstEnergy Corp.
	No
	We understand and appreciate the drafting team's intent to eliminate the burden on a Transmission Operator with one radial connection under 200 kV to the BES by refining the applicability to exclude such entities. However, what if there was a single radial 200kV+ line to load not owned by the traditional TO/TOP in the area? Would the owner of the facility be required to have a primary/back-up control center? The applicability section of this standard is not the approriate place to address these issues. The exclusion for TOPs operating only radial transmission lines serving load is contained in Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Exclusion issues should be vetted and managed in the Rules of Procedure and the registration processes. The applicability of this standard should point to the functional model entities used in the registration process. It may be simpler to state the applicability as follows related to the TOP: "Transmission Operator of Bulk Electric System (BES) facilities and/or any non-BES facilities, deemed materially important to the BES by the Regional Entity." We believe the SDT should avoid the word "critical" as it may cause confusion with the CIP references to Critical Assets.
	Yes
	We agree that the transition time frames should be equivalent for all applicable entities.
	Yes
	No
	Measures 1, 2, 3, 6, and 8 require a dated Operating Plan but there is nothing in the associated requirements that states the plan shall contain an effective date. The requirements section of the standard should cover all of the expectaions Measures should not add to the requirements. We believe adding a subrequirement to R1 that requires the plan have an effective date, would provide the appropriate source documents to substatiate compliance for all requirements associated with the Operating Plan. Also, with the span of time that elapses between each compliance audit, the drafting team should consider whether the measures section should include statements to retain copies of revisions to the plan for the specified retention period as evidence of compliance. The measures could be simplified by not repeating text that has already been stated, so that the main point is clearly evident. For example in Measure M2 the intent of the requirement and measure is ensure a valid copy of the Operating Plan is located at both the primary and back-up centers. Therefore it may be more concise to say: "Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have evidence of a vaild Operating Plan, meeting R1/M1, is in force and located at its primary and back-up operating centers. It is suggested that the SDT consider this advice/recommendation throughout all measures to improve readability so that readers can quickly understand what is needed. There should be no need to re-peat text from other requirements/measures already covered within the standard.
	No
	The VSLs for Requirement 3 implies this method of operation is employed only when a TOP is directing operations through more than one other entity. We don't believe this to be the norm. The drafting team should consider the failure to include provisions for the loss of a percentage of such entity's or entities' total control functionality rather than basing the compliance measurement on the percentage of entities. For the requirement 4, the VSL's should be revised based on the needed revisions to the associated requirement. For the requirement 5, the VSL's should be revised based on the needed revisions to the associated requirement. For requirement 6, we believe a VSL could be written for each severity level using the time requirements established. For instance, high could apply to 18 months and severe to 21 months. For requirement 7, the VSL's should be revised based on the needed revisions to the associated requirement. For requirement 8, there is nothing in Requirment 8 as currently proposed by the drafting team that requires a two hour test. If there is an expectation for a test of the backup center to last two hours, it should be stated in the requirement. The VSL for Requirement 8 should be rewritten based on the needed revisions to the associated requirement. For requirement 9, the Regional Entity either already has the evidence or a violation has occurred because the report was not submitted on time. The responsible entity should not have to redemonstrate to the compliance auditor that it submitted the plan to the Regional Entity since the compliance auditor is the Regional Entity.
	Yes

	Yes
	Requirement R1.6.2 is not clear. The meaning of primary/backup is ambiguous. This requirement should be revised to state, “Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during simultaneous outages of both the primary and backup functionality.” Requirements R4 and R5 as written are very confusing. It appears the drafting team’s expectation is for an entity to have either the primary or backup control center available and in use at all times. If that is the intent, the requirement should say that. Also, it appears the drafting team’s expectation is compliance with all applicable Reliability Standards at all times. This is a requirment of the mandatory and enforceable reliabilty standards. R4 and R5 should be deleted. Requirement R6 as written is confusing. Who is intended to approve the Operating Plan for the backup functionality? Is it the intent of the drafting team for each entity to approve its own plan? Should these plans be required to be approved by a senior executive of the company? Should these plans be approved by the RC? Requirement R9 should be revised to state, “Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of either its primary or backup capability due to a catastrophic event and anticipates the loss of either its primary or backup capability will last for more than six calendar months, shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability.” This requirement as currently proposed allows an entity 6 months to restore its backup functionality. Backup functionality should be restored as soon as repairs can be made in most cases. Only in a catastrophic event should an entity be allowed to be without backup for such a long period of time. Requirement 7 is unncessary. If a RC, TOP and BA, can comply with all applicable requirements at all times from a backup control center that relies on facilities of their primary control center, then they have met the intent of the standards.
	Yes
	Yes - the standard is much improved in defining expectations of implementing back-up capability, testing of the back-up center etc. Although the time allowed to implement backup capability could be perceived to be an increase over the existing EOP-008-1 standard, the existing standard does not include a hard and fast rule on a 1 hour implementation. In EOP-008-1, an entity was permitted to have "interim provisions" without a hard-stop on the time needed to implement the back-up center. In the proposed EOP-008-2 standard, we believe the SDT made the appropriate steps to put a firm time limit for implementation and we feel the 2 hour limit is sufficient. The need to utilize one's backup capability is a rare event and the adjustment made should not adversely effect reliability of the BES.
	Individual
	H. Deon Murphy
	Bureau of Reclamation
	No
	In the applicability of the current draft, the term "Regional Entity" appears. This term is not a NERC defined term, nor is it added for this document, so to whom or what it refers is unclear. What entity(s) are expected to demonstrate the criticality? Is this Entity the RRO, a RC, or some other party? In addition the term "nonradial" is not clear, is it non-radial with respect to generation and/or load? The applicability should be for all Transmission Operators, with a provision to allow them to be granted a waiver from their RRO if that TOP can demonstrate why the standard should not apply to them.
	Yes
	Yes
	No
	These measures should be consistent with other existing data retention measures that have already been approved.
	Yes
	Yes
	Yes
	In requirement R1.1 the term "for a prolonged period of time" has been added. As this is a nebulous addition that does not add clarification to the requirement it should be deleted. Requirement R3 requires the TOP when "…directing BES operations through other entities…" to "include provisions for the loss of such other entity’s control functionality in its Operating Plan for backup functionality." We agree with this requirement, however, there is no

	requirement for such provision to ever be coordinated with the other entity, or for the other entity to even be informed. We suggest adding to R3 or R6, language similar to: "Those provisions in the Operating Plans for backup functionality that deal with the loss of another entity's control functionality shall be coordinated with that entity when the Operating Plans are reviewed annually."
	No
	With regard to the decision not to include Generator Operator (GOP) centrally dispatched control centers we are concerned with the introduction of the degree of BES risk to the decision to make a standard applicable to a Reliability Function or to include it in a requirement. This is exemplified in the SDT's statement in their consideration: "The primary issue of whether centrally dispatched generation control centers should be applicable entities to the EOP-008-1 standard is an issue of risk exposure to the reliable operation of the BES." We believe that the usual emphasis is on risk avoidance, and such a change in the basis of what is included or covered by a standard or to whom it applies should be determined by using the NERC ANSI approved Standards process and not a single drafting team.
	Group
	ISO RTO Council Standards Review Committee
	Charles Yeung
	Southwest Power Pool
	No
	We agree with the drafting team's intent to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV by limiting TOP applicability. However, this is a registration issue and really identifies an issue with the definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration. TOPs operating only radial transmission lines serving load are already excluded from registering per Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Limiting applicability further than this on radial transmission lines in essence redefines the BES and that is not a function of a standard. Please remove the language limiting the applicability.
	No
	We agree with and thank the drafting team for making the timeframes equivalent. However, we continue to believe that the new requirement is actually less stringent than the existing requirement. While the new requirement specifies that the backup plan must be implemented in two or less hours, the existing requirement specifies that interim provisions must be made if it will take more than one hour to implement the backup capability. Thus, even if the backup capability is not fully implemented within one hour, the responsible entity still has to have an alternative to operate without the primary control center within an hour. We also question what the 2 hours is based on. Have industry surveys or compliance audit results been utilized that demonstrate that two hours is required to fully implement the back up capability plan instead of the one? We recommend changing the implementation time back to one hour.
	No
	R7 should be a sub-requirement of R1. Thus, it should not have a VRF. The VRF for R8 should be lower. Given that the Operating Plan needs to be tested more frequently than annually to ensure that the backup capability is available when it is needed, this requirement is clearly intended to be administrative. Requirement 9 should be removed from the standard. This is, in essence, a requirement for an N-2 contingency. It is such a rare occurrence to operate from a backup center for an extended period of time that this requirement is not needed. If the RC, TOP or BA must operate from their backup center or utilizes their backup capability for an extended period of time, they should work with NERC and the Regional Entity to address the specific situation rather than having a requirement that dictates a time frame. We assess the reliability impact of (R9) failure to come up with a plan 6 months after an entity has experienced a loss of its primary control center or backup capability and expects such loss to last for 6 months or more is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower VSL be assigned to this requirement if the the requirement is retained.
	No
	Measures 1, 2, 3, 6, and 8 require dated, current, in force Operating Plan but there is no time requirement in the associated requirements. Measures should not add to the requirements. What does current really mean? How would the compliance auditor know if the Operating Plan is current given that the requirement does not mention date or time? We suggest removing the term in force because it does not add anything to the requirement. Why would the responsible entity supply an Operating Plan to the compliance auditor that wasn't in force? Measures 1, 2, 3, 6, and 8 also state that evidence of the last issue of the Operating Plan is required. There is nothing in the associated requirements about issuing. Thus again the measures are adding to the requirements but should not. To who is the Operating Plan required to be issued in the Measures? Part of the issue with Measure 6 is that its associated requirement really should be a sub-requirement of requirement 1. This would solve some of the issues with Measure 1. A large part of the issue with Measures 2, 3, 6, and 8 appear to be overuse of copy and paste. The only requirement associated with these measurements that really needs a dated Operating plan as evidence is

	requirement 1 but as the requirement is currently written it does not require the Operating Plan to have a date. Measure 7 should not include a requirement for dated evidence. What is really needed is that the Operating Plan evidence presented should have a date and the Operating Plan should be verified to not depend on the primary control center. The compliance auditors could not practically verify that the backup capability or backup control center does not depend on the primary control center. Thus, the requirement associated with Measure 7 is really a sub-requirement of requirement 1. Measurement 9 should not require the RC, BA, and TOP to have evidence that a plan has been submitted to its Regional Entity when it loses its primary control center or backup capability or backup control center because the Regional Entity is the Compliance Enforcement Authority. The Regional Entity will know when the plan is received.
	No
	Guideline 3 of FERC's order conditionally approving VSLs for the original 83 regulatory approved standards stipulates that the VSL should not add to the requirement. The Lower VSL of R1 does add a requirement for the document to be dated which violates Guideline 3. Requirement 1 fits the multi-component category of the VSL Guidelines. This category puts the number of sub-requirements that are missing from the Operating Plan into quartiles. Thus, the Lower VSL would be missing one or two sub-requirements the Moderate VSL would be missing three or four sub-requirements the High VSL would be missing five to six sub-requirements and the Severe VSL would be missing seven sub-requirements or the plan would not exist. The VSLs for Requirement 2 should use the term back-up capability along with primary control center for consistency with the requirements. R2 requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guideline. The VSLs for Requirement 3 really don't make any sense. It implies there may be more than one other entity that a TOP is directing BES operations through. We don't think that this is likely. Additionally, the VSLs as written do not seem to fit any category within the VSL guidelines document. Why would the VSLs not be divided into quartiles based the number of entities? For the requirement 4, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities forseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the BA or TOP has a backup capability plan, isn't the BA or TOP still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. For the requirement 5, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities forseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the RC has a backup control center, isn't the RC still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? Perhaps the drafting team should consider applying VSLs based on if monitoring, control, logging and alarming are included in the backup capability. The Severe level should include a condition that the BA or TOP provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. In its order approving VSLs, the FERC stated in paragraph 27 that they prefer gradated VSLs whenever possible. For requirement 6, we believe a VSL could be written for each severity level using the time requirements established. For instance, high could apply to 18 months and severe to 21 months. Additionally, the VSLs for requirement 6 violate FERC's guideline 3 by requiring the Operating Plan to be dated. The associated requirement does not mention dating. There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not update its plan after 18 months or 120 calendar days after changes were made to the backup capability; a Severe for failing to update its plan for a longer time period or at all. For requirement 7, the only VSL does not make any sense. The VSL implies that the responsible entity may provide evidence that backup plan depends on the primary control center. Why would the responsible entity providing evidence of non-compliance be a severity level? The purpose of providing evidence is to demonstrate compliance. Is this requirement 7 even needed? There are requirements in this standard that require a backup plan. The responsible entity is responsible to comply with this standard and with all other standards even when operating with the backup plan. Can they comply with other standards if the backup plan depends on the primary control center and the primary control center is destroyed? No. Thus, they would violate many other standards. Thus, requirement 7 is implied and not needed explicitly as a requirement. For requirement

	8, we do not support a mandatory testing time of two hours or a transition time of two hours. However, considering the requirement as written, we suggest the drafting team could develop VSLs for all levels. VSLs could be written as: Lower: Tested the back plan for 90 minutes or more but less than two hours or The transition time was more than two hours but less than or equal to 3 hours. Moderate: Tested the back plan for one hour or more but less than 90 minutesThe transition time was more than three hours but less than or equal to four hours. High: Tested the backup plan for 30 minutes or more but less than one hour or The transition time was more than four hours but less than or equal to five hours. Severe: Tested the back up plan for less than 30 minutes or The transition time was more than five hours or or the test results and lessons learned were not incorporated in subsequent revisions.. For requirement 9, the VSL perpetuates some of the problems that are currently occuring with compliance monitoring of requirements that have periodic reporting requirements to the Regional Entity. The Regional Entity either already has the evidence or a violation has occurred because the report was not submitted on time. The responsible entity should not have to redemonstrate to the compliance auditor that it submitted the plan to the Regional Entity since the compliance auditor is the Regional Entity.
	Yes
	Yes
	We do not agree with the transition requirement of two hours. We believe that the transition time as worded in the existing standard actually requires full implementation of the backup plan in one hour or to provide an alternative to continue operations. Thus, we assume the drafting team must have had a compelling reason for changing to two hours. What is the reason? Is there data justifying it? We recommend changing it back to one hour. Requirement 2 is not needed. What is important is that the plan gets implemented when needed not that some compliance auditor can verify there is a copy of the plan at the backup and primary control centers. Most entities are going to have their plans at the primary and backup control centers to allow them to implement the plan. If they don't, they likely won't be able to implement their plan in the required time frame. Thus, they will already be violating another requirement so lets not provide an opportunity for double jeopary. Requirement 3 stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." We do not agree that this requirement should apply to the TOP only. There might well be situations that an RC or a BA directs it operations through other entities as well. We suggest the requirement should also include the RC and the BA by rewording the requirement to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations…" Wording of requirement 3 is ambiguous in that in some areas/jurisdictions, there are multiple TOPs that one of them directs the operations of the others. For example, an ISO is registered as a TOP while a transmission entity (an owner, for example) within the ISO footprint is also registered as a TOP. The two TOPs perform distinctly different tasks and may even have their tasks and responsibilities clearly stipulated in an agreement, market rule or regional reliability plan. The ISO-TOP directs operations of the transmission-entity-TOP while the latter may be solely responsible for switching operations and maintenance. Both need to have backup capability. The way R3 is worded can be interpreted that the ISO-TOP needs to be responsible for the backup capability of the transmission-entity-TOP. We do not believe this is the intent of R3, and this is not practical. To clarify this situation, we suggest R3 to be reworded to: "Each applicable Transmission Operator delegating its tasks for BES operations to other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." In other words, this requirement only applies to a TOP if it delegates it task (for which it is still fully responsible) to another entity. For Requirement 4, we are not sure why the condition: "…during the time period when the primary control center functionality and the backup functionality are both available for use…" is included since having both control center functionality available for use suffice to meet the condition for: "…have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simply stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed. We further do not understand the clause "that provides functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator". The RC is already required to comply with these standards regardless of whether they operate from the backup center or the primary center. Requirements should never require compliance with other requirements because it creates the opportunity for double jeopardy. For Requirement 5, please see our comments on regarding Requirement 4.. We do not think Requirement 5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. Furthermore, we don't understand the need for the statement "sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority or Transmission Operator respectively" in the requirement. The BA and TOP are already required to comply with these standards regardless of whether they operate from the location of their backup capability or the primary center. Requirement 6 is really a sub-requirement of requirement 1. Sub-requirement 6.1 is confusing. Because it is a sub-requirement, it must apply to requirement 6. Thus, it would seem that the sub-requirement is requiring the annual review and approval to occur withing 60 days of any changes. What if there are multiple changes in the year? From this perspective, it appears that the sub-requirement is intended to reflect that changes can occur at any time. To clarify the requirement, we

	suggest the following language as a sub-requirement of R1 along with striking requirement 6 and 6.1: "Each RC, BA an TOP shall review and approve its Operating Plan for backup functionality annually and within sixty calendar days of any changes to the backup location, capabilities or contact information, modify the Operating Plan to reflect the changes." Requirement 7 is unncessary as an explicit requirement. Each RC, TOP and BA is required to comply with all applicable requirements even if they are operating from the location of their backup functionality or backup control center. If their backup functionality relies on the primary control center, the RC, TOP and BA will be unable to comply with numerous other requirements in the event that they lose the functionality of their primary control center. Requirement 8 is not needed and does not accomplish the goal of ensuring the backup capability is available when needed. In reality, an RC, TOP and BA will have to confirm that availability of their backup functionality significantly more often than annually to ensure that backup functionality is available when needed. In fact, most RC, TOP, and BA already confirm the availability of their backup capability more often than annually even though the current requirement is for an annual test. They do this not because of the testing requirement but because of the need to continue to comply with other applicable requirements. If the other standards requirements already drive the entities to exceed this requirement, why is it needed? It is not. Requirement 9 should be struck. This requirement essentially represents an N-2 condition. The requirements should not try to anticipate extreme conditions such as this. Because RC, TOP and BA are still required to comply with the requirements even if they lose one of the operating centers or backup capability, the RC, TOP and BA will have to make plans to operate in the event of the failure of their last operable control center. Thus, failure to begin developing a plan to replace the backup capability or primary control center will surely result in a violation of another requirement (actually likely many requirements).
	No
	We believe that the standard may actually reduce reliability slightly given that the timing requirement for operating utilizing your backup capability has been increased. Given that the need to utilize your backup capability is a rare event, even this reduced level of reliability may be acceptable.
	Individual
	Rick White
	Northeast Utilities
	No
	The addition of the language, "operating Facilities at 200 kV or above, or nonradial Facilities above 100 kV", is not appropriate.
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	The revised language in R4 and R5 does not clarify the intent, which we believe is to prevent a violation for not having a backup facility during the time period when it has become necessary to utilize the backup facility. i.e. - that a backup for the backup is not required. We believe this clarification is not needed as separate requirements and results in confusing text. One possible solution would be to eliminate R4 & R5 and include the clarifying thoughts in the Measures. R7 includes the necessary language from R4 & R5, and could be included as one of the sub-requirements in R1, or combined with R1.3.
	Yes
	Group
	Midwest ISO Standards Collaborators
	Jason Marshall
	Midwest ISO
	No

	We agree with the drafting team's intent to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV by limiting TOP applicability. However, this is a registration issue and really identifies an issue with the definition definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration. TOPs operating only radial transmission lines serving load are already excluded from registering per Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Limiting applicability further than this on radial transmission lines in essence redefines the BES and that is not a function of a standard. Please remove the language limiting the applicability. We urge the drafting team to communicate the need to limit applicability of certain requirements in the registration process. This is a broader problem that NERC needs to resolve.
	Yes
	No
	R7 should be a sub-requirement of R1. Thus, it should not have a VRF. The VRF for R8 should be lower. Given that the Operating Plan needs to be tested more frequently than annually to ensure that the backup capability is available when it is needed, this requirement is clearly intended to be administrative. Requirement 9 should be removed from the standard. This is, in essence, is a requirement for an N-2 contingency. It is such a rare occurrence to operate from a backup center for an extended period of time that this requirement is not needed. If the RC, TOP or BA must operate from their backup center or utilizing their backup capability for an extended period of time, they should work with NERC and the Regional Entity to address the specific situation rather than having a requirement that dictates a time frame.
	No
	Measures 1, 2, 3, 6, and 8 require dated, current, in force Operating Plan but there is no time requirement in the associated requirements. Measures should not add to the requirements. What does current really mean? How would the compliance auditor know if the Operating Plan is current given that the requirement does not mention date or time? We suggest removing the term in force because it does not add anything to the requirement. Why would the responsible entity supply an Operating Plan to the compliance auditor that wasn't in force? Measures 1, 2, 3, 6, and 8 also state that evidence of the last issue of the Operating Plan is required. There is nothing in the associated requirements about issuing. Thus again the measures are adding to the requirements but should not. To who is the Operating Plan required to be issued in the Measures? Part of the issue with Measure 6 is that its associated requirement really should be a sub-requirement of requirement 1. This would solve some of the issues with Measure 1. A large part of the issue with Measures 2, 3, 6, and 8 appear to be overuse of copy and paste. The only requirement associated with these measurements that really needs a dated Operating plan as evidence is requirement 1 but as the requirement is currently written it does not require the Operating Plan to have a date. Measure 7 should not include a requirement for dated evidence. What is really needed is that the Operating Plan evidence presented should have a date and the Operating Plan should be verified to not depend on the primary control center. The compliance auditors could not practically verify that the backup capability or backup control center does not depend on the primary control center. Thus, the requirement associated with Measure 7 is really a sub-requirement of requirement 1. Measurement 9 should not require the RC, BA, and TOP to have evidence that a plan has been submitted to its Regional Entity when it loses its primary control center or backup capability or backup control center because the Regional Entity is the Compliance Enforcement Authority. The Regional Entity will know when the plan is received.
	No
	Guideline 3 of FERC's order conditionally approving VSLs for the original 83 regulatory approved standards stipulates that the VSL should not add to the requirement. The Lower VSL of R1 does add a requirement for the document to be dated which violates Guideline 3. Requirement 1 fits the multi-component category of the VSL Guidelines. This category puts the number of sub-requirements that are missing from the Operating Plan into quartiles. Thus, the Lower VSL would be missing one or two sub-requirements the Moderate VSL would be missing three or four sub-requirements the High VSL would be missing five to six sub-requirements and the Severe VSL would be missing seven sub-requirements or the plan would not exist. The VSLs for Requirement 2 should use the term back-up capability along with primary control center for consistency with the requirements. We agree with these levels. The VSLs for Requirement 3 really don't make any sense. It implies there may be more than one other entity that a TOP is directing BES operations through. We don't think that this is likely. Additionally, the VSLs as written do not seem to fit any category within the VSL guidelines document. Why would the VSLs not be divided into quartiles? For the requirement 4, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities forseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the BA or TOP has a backup capability plan, isn't the BA or TOP still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? For the requirement 5, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date

	which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities forseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the RC has a backup control center, isn't the RC still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? Perhaps the drafting team should consider applying VSLs based on if monitoring, control, logging and alarming are included in the backup capability. In its order approving VSLs, the FERC stated in paragraph 27 that they prefer gradated VSLs whenever possible. For requirement 6, we believe a VSL could be written for each severity level using the time requirements established. For instance, high could apply to 18 months and severe to 21 months. Additionally, the VSLs for requirement 6 violation FERC's guideline 3 by requiring the Operating Plan to be dated. The associated requirement does not mention dating. For requirement 7, the only VSL does not make any sense. The VSL implies that the responsible entity may provide evidence that backup plan depends on the primary control center. Why would the responsible entity providing evidence of non-compliance be a severity level? The purpose of providing evidence is to demonstrate compliance. Is this requirement 7 even needed? There are requirements in this standard that require a backup plan. The responsible entity is responsible to comply with this standard and with all other standards even when operating with the backup plan. Can they comply with other standards if the backup plan depends on the primary control center and the primary control center is destroyed? No. Thus, they would violate many other standards. Thus, requirement 7 is implied and not needed explicitly as a requirement. For requirement 8, we do not support a mandatory testing time of two hours or a transition time of two hours. However, considering the requirement as written, we suggest the drafting team could develop VSLs for all levels. VSLs could be written as: Lower: Tested the back plan for 90 minutes or more but less than two hours or The transition time was more than two hours but less than or equal to 3 hours or the test results and lessons learned were not incorporated in subsequent revisions. Moderate: Tested the back plan for one hour or more but less than 90 minutes The transition time was more than three hours but less than or equal to four hours. High: Tested the backup plan for 30 minutes or more but less than one hour or The transition time was more than four hours but less than or equal to five hours. Severe: Tested the back plan for less than 30 minutes or The transition time was more than five hours. For requirement 9, the VSL perpetuates some of the problems that are currently occuring with compliance monitoring of requirements that have periodic reporting requirements to the Regional Entity. The Regional Entity either already has the evidence or a violation has occurred because the report was not submitted on time. The responsible entity should not have to redemonstrate to the compliance auditor that it submitted the plan to the Regional Entity since the compliance auditor is the Regional Entity.
	Yes
	No
	Requirement 2 is not needed. What is important is that the plan gets implemented when needed not that some compliance auditor can verify there is a copy of the plan at the backup and primary control centers. Most entities are going to have their plans at the primary and backup control centers to allow them to implement the plan. If they don't, they likely won't be able to implement their plan in the required time frame. Thus, they will already be violating another requirement so lets not provide an opportunity for double jeopary. Requirement 4 should strike "that provides functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator". The RC is already required to comply with these standards regardless of whether they operate from the backup center or the primary center. Requirement 5 should strike "sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority or Transmission Operatore respectively". The BA and TOP are already required to comply with these standards regardless of whether they operate from the location of their backup capability or the primary center. Further, we urge the drafting team to consider combining requirements 4 and 5 to require full backup control centers for the TOP and BA as well as the RC. Requirement 5 is already stringent enough that a backup control center is likely required anyway. Combining the requirements just simplifies the standards. Requirement 6 is really a sub-requirement of requirement 1. Sub-requirement 6.1 is confusing. Because it is a sub-requirement, it must apply to requirement 6. Thus, it would seem that the sub-requirement is requiring the annual review and approval to occur withing 60 days of any changes. What if there are multiple changes in the year? From this perspective, it appears that the sub-requirement is intended to reflect that changes can occur at any time. To clarify the requirement, we suggest the following language as a sub-requirement of R1 along with striking requirement 6 and 6.1: "Each RC, BA an TOP shall review and approve its Operating Plan for backup functionality annually and within sixty calendar days of any changes to the backup location, capabilities or contact information, modify the Operating Plan to reflect the changes." Requirement 7 is unncessary as an explicit requirement. Each RC, TOP and BA is required to comply with all applicable requirements even if they are operating from the location of their backup functionality or backup control center. If their backup functionality relies on the primary control center, the RC, TOP and BA will be unable to comply with numerous other requirements in the event that they lose the functionality of their primary control center. Requirement 8 is not needed and does not accomplish the goal of ensuring the backup capability is available when needed. In reality, an RC, TOP and BA will have to operate utilizing backup functionality significantly more often than annually to ensure that backup functionality is available when needed. In fact, most RC, TOP, and BA already test their backup capability more often than annually even though the current

	requirement is for an annual test. They do this not because of the testing requirement but because of the need to continue to comply with other applicable requirements. If the other standards requirements already drive the entities to exceed this requirement, why is it needed? It is not. Requirement 9 should be struck. This requirement essentially represents an N-2 condition. The requirements should not try to anticipate extreme conditions such as this. Because RC, TOP and BA are still required to comply with the requirements even if they lose one of the operating centers or backup capability, the RC, TOP and BA will have to make plans to operate in the event of the failure of their last operable control center. Thus, failure to begin developing a plan to replace the backup capability or primary control center will surely result in a violation of another requirement (actually likely many requirements).
	Yes

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on 2nd Draft of EOP-008-1 — Backup Facilities (Project 2006-04)

The Backup Facilities Standards Drafting Team thanks all commenters who submitted comments on the 2nd draft of reliability standard EOP-008-1 — Loss of Control Center Functionality. The proposed standard was posted for a 45-day public comment period from August 26, 2008 through October 9, 2008. The stakeholders were asked to provide feedback on the proposed metrics through a special electronic Standard Comment Form. There were more than 38 sets of comments, including comments from more than 95 different people from approximately 50 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Backup_Facilities.html

Due to the large number of comments received, the SDT is recommending a third posting for this project.

Based on industry comments, the applicability exclusion for certain Transmission Operators has been deleted (Section 4.1.2) and the following requirements have been changed due to industry comments: R1, R1.2, R1.5, R1.6, R1.6.2, R2, R3, R4, R4.1, R4.2, R5, R5.1, R5.2, R6.1, R7, R8.1, and R8.3. In addition, the following measures were changed due to industry comments: M1, M2, M3, M4, M5, M6, M7, and M8. Also, VSL for the following requirements were changed based on comments: R1, R2, R3, R4, R5, R6, R7, and R8.

The SDT has also changed the entity cited in Requirement R9 from 'Regional Entity' to 'Reliability Assurer' in line with version 4 of the Functional Model.

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 Vice President and 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.

Index to Questions, Comments, and Responses

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

<table>
<tr><th colspan="2" rowspan="2">Commenter</th><th rowspan="2">Organization</th><th colspan="10">Industry Segment</th></tr>
<tr><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th></tr>
<tr><td>1.</td><td>Thad Ness</td><td>AEP</td><td>x</td><td></td><td>x</td><td></td><td>x</td><td>x</td><td></td><td></td><td></td><td></td></tr>
<tr><td>2.</td><td>Jeff Hackman</td><td>Ameren</td><td>x</td><td></td><td>x</td><td></td><td>x</td><td>x</td><td></td><td></td><td></td><td></td></tr>
<tr><td>3.</td><td>Denise Koehn</td><td>Bonneville Power Administration</td><td>x</td><td></td><td>x</td><td></td><td>x</td><td>x</td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="13">
<table>
<tr><th>Additional Member</th><th>Additional Organization</th><th>Region</th><th>Segment Selection</th><th></th></tr>
<tr><td>1.</td><td>James Burns</td><td>Transmission Technical Operations</td><td>WECC</td><td>1</td></tr>
</table>
</td></tr>
<tr><td>4.</td><td>David Carpenter</td><td>Brazos Electric Power Cooperative, Inc.</td><td>x</td><td></td><td>x</td><td></td><td>x</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>5.</td><td>H. Deon Murphy</td><td>Bureau of Reclamation</td><td></td><td></td><td></td><td></td><td>x</td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
6.	Paul Rocha	CenterPoint Energy	x									
7.	Dan Brotzman	ComEd / Exelon	x		x							
8.	Jianmei Chai	Consumers Energy Company			x	x	x					
9.	Greg Rowland	Duke Energy	x		x		x	x				
10.	Greg Mason	Dynegy					x					
11.	Vann Weldon	Electric Reliability Council of Texas, Inc.		x								x
12.	Edward J Davis	Entergy Services, Inc	x									
13.	Will Franklin (Entergy)	Entergy System Planning & Operations (Generation & Marketing)						x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Joel Plessinger	Entergy SPO	SERC	6
2.	Terri Benoit	Entergy SPO	SERC	6
3.	Margaret Hebert	Entergy SPO	SERC	6
4.	George Raesis	Entergy SPO	SERC	6

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
14.	Doug Hohlbaugh	FirstEnergy Corp.	x		x	x	x	x				

Additional Member	Additional Organization	Region	Segment

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

				Selection
1.	Doug Hohlbaugh	FirstEnergy Corp	RFC	1, 3, 4, 5, 6
2.	David Folk	FirstEnergy Corp	RFC	1, 3, 4, 5, 6
3.	Sam Ciccone	FirstEnergy Corp	RFC	1, 3, 4, 5, 6
4.	John Martinez	FirstEnergy Corp	RFC	1, 3, 4, 5, 6

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Roger Champagne	Hydro-Québec TransÉnergie (HQT)	x									
16.	Dan Rochester	Independent Electricity System Operator		x								
17.	Kathleen Goodman	ISO New England Inc		x								
18.	Charles Yeung (SPP)	ISO/RTO Council Standards Review Committee		x								

Additional Member	Additional Organization	Region	Segment Selection	
1.	Anita Lee	Alberta Electric System Operator	WECC	2
2.	Lourdes Estrada-Salinero	California ISO	WECC	2
3.	H. Steven Myers	ERCOT	ERCOT	2
4.	Ben Li	IESO	NPCC	2
5.	Matt Goldberg	ISO New England	NPCC	2

6.	Bill Phillips	Midwest ISO	RFC	2
7.	Jim Castle	New York ISO	NPCC	2

Commenter		Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
19.	Debra Yinger	ITC	x									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Elizabeth Howell		RFC	1
2.	Michael Ayotte		RFC	1

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
20.	Kris Manchur	Manitoba Hydro	x		x		x	x				
21.	Jason Marshall	Midwest ISO		x								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kirit Shah	Ameren	SERC	1
2.	Joe Knight	Great River Energy	MRO	1, 3, 5
3.	Jim Cyrulewski, P.E.	JDRJC Associates	RFC	8

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
22.	Joe DePoorter (MGE)	MRO NERC Standards Review Subcommittee			x	x	x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6

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

2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Charles Lawrence	ATC	MRO	1
6.	Ken Goldsmith	ALTW	MRO	4
7.	Tom Mielnik	MEC	MRO	1, 3, 5, 6
8.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
9.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
10.	Eric Ruskamp	BEPC	MRO	1, 3, 5, 6
11.	Joseph Knight	GRE	MRO	1, 3, 5, 6
12.	LArry Brusseau	MRO	MRO	10
13.	Michael Brytowski	MRO	MRO	10

			1	2	3	4	5	6	7	8	9	10
23.	Rick White	Northeast Utilities	x									
24.	Guy Zito	NPCC										x

Additional Member	Additional Organization	Region	Segment Selection	
1.	Ralph Rufrano	New York Power Authority	NPCC	5

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

2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	Rick White	Northeast Utilities	NPCC	1
4.	Greg Campoli	New York Independent System Operator	NPCC	2
5.	Kathleen Goodman	ISO - New England	NPCC	2
6.	Chris De Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Don Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
8.	Brian Evans-Mongeon	Utility Services	NPCC	6
9.	Mike Gildea	Constellation Energy	NPCC	6
10.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
11.	Dan Rochester	Independent Electricity System Operator	NPCC	2
12.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
13.	Lee Pedowicz	NPCC	NPCC	NA
14.	Gerry Dunbar	NPCC	NPCC	NA
15.	Brian Hogue	NPCC	NPCC	NA

25.	Greg Ward / Darryl Curtis	Oncor Electric Delivery	x									
26.	Richard Kafka	Pepco Holdings, Inc. - Affiliates	x									

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

Additional Member	Additional Organization	Region	Segment Selection	
1.	Dave Thorne	Potomac Electric Power Co	RFC	1
2.	Vic Davis	Delmarva Power & Light Co	RFC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
27.	Tom Moleski	PJM Interconnection		x								
28.	D. Bryan Guy	Progress Energy Carolinas, Inc.	x		x		x					
29.	Marty Berland	Progress Energy-Florida	x		x		x	x				
30.	Todd Lietz	Puget Sound Energy	x		x							
31.	Rao Somayajula	ReliabilityFirst Corporation										x
32.	Randy Schimka	San Diego Gas and Electric	x		x	x	x					
33.	Terry L. Blackwell	Santee Cooper	x									

Additional Member	Additional Organization	Region	Segment Selection	
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Glenn Stephens	Santee Cooper	SERC	1
3.	Wayne Ahl	Santee Cooper	SERC	1
4.	Jim Peterson	Santee Cooper	SERC	1

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

5.	Rene' Free	Santee Cooper	SERC	1

			1	2	3	4	5	6	7	8	9	10
34.	Richard Salgo	Sierra Pacific Power Co. (dba NV Energy)	x									
35.	Roman Carter	Southern Company Transmission	x									

Additional Member	Additional Organization	Region	Segment Selection	
1.	Marc Butts	Southern Transmission	SERC	1
2.	Jim Busbin	Southern Transmission	SERC	1
3.	JT Wood	Southern Transmission	SERC	1
4.	Raymond Vice	Southern Transmission	SERC	1
5.	Chris Wilson	Southern Transmission	SERC	1
6.	Terry Coggins	southern Transmission	SERC	1

			1	2	3	4	5	6	7	8	9	10
36.	Linda Perez (WECC)	WECC Reliability Coordinator Comment Working Group										x
37.	Robert Temple	Western Area Power Administration	x									
38.	Alice Druffel	Xcel Energy	x		x		x	x				

1. The SDT has made a change in the applicability of the Transmission Operator (see Section 4.1.2). Do you agree with the change that was made? If not, please provide specific suggestions for improvement.

Summary Consideration:

Many commenters expressed disapproval of the applicability exclusion proposed for certain Transmission Operators. Based on these comments and further research by the SDT, it appears that the exclusion is not necessary as the intent of the SDT is covered in the NERC "Statement of Compliance Registry Criteria (Revision 5.0)" and Section 501 (specifically Section 501 1.2.3) of the NERC Rules of Procedure which addresses the entities who should be registered as a TOP, and therefore, subject to the applicable provisions of this standard. Therefore, the exclusionary language of Section 4.1.2 has been deleted.

4.1.2. Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.

Organization	Question 1:	Question 1 Comments:
Manitoba Hydro	No	I suggest the applicability for the Transmission Operator be changed to the following: "Transmission Operator operating Bulk Electric System (BES) Facilities at 100 kV or higher, including those Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System." The Transmission Operator that just has a radial connection to the BES is taken care of by the definition of Bulk Electric System which states: "Radial transmission facilities serving only load with one transmission source are generally not included in this definition."
Sierra Pacific Power Co. (dba NV Energy)	No	We would recommend the deletion of the last portion of the applicability statement in 4.1.2. The suggestion is to delete "or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)". We believe this part of the applicability is highly subjective and would result in uncertainty among entities who are excluded today, but could suddenly be subject to this Standard due to a subjective judgment call made by their Regional Entity at some point in the future. The Regional Entities presently do not exhibit consistency in their determination of the components of the BES, and quite likely would be even less consistent in a determination of facilities "critical to the reliability of the BES". The applicability statement that would remain after this suggested deletion would not only be clear and objective, it would also point to the specific entities that should be responsible for complying with this Standard.
Response: Based on your comment and many others, the SDT has decided to remove all qualifying language from 4.1.2 and list only		

Organization	Question 1:	Question 1 Comments:
"Transmission Operator." We believe, and in addition are convinced by comments received, that the NERC "Statement of Compliance Registry Criteria (Revision 5.0)" and Section 501 (specifically Section 501 1.2.3) of the NERC Rules of Procedure satisfactorily addresses which entities should be registered as a TOP, and therefore, subject to the applicable provisions of this standard. The standards drafting process is not the appropriate venue for addressing inconsistency issues regarding the Regional Entities. This should be addressed directly with the Regional Entities, or if necessary, with NERC or FERC. **4.1.2** Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.		
NPCC	No	The addition of the wording "operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV," is not appropriate.
Hydro-Québec TransÉnergie (HQT)	No	The addition of the wording "operating Facilities at 200 kV or above, or non-radial Facilities above 100 kV," is not appropriate and should be removed.
Northeast Utilities	No	The addition of the language, "operating Facilities at 200 kV or above, or non radial Facilities above 100 kV", is not appropriate.
Entergy Services, Inc	No	We suggest the Applicability to Transmission Operators (4.1.2) be revised as follows to improve readability, to address the ambiguity of the use of the word "critical", and to address section c of the Applicability statement. Use of the term "critical" is vague and causes confusion as evidenced in the Vegetation standards, Cyber standards, and others. We suggest not using "critical" and revising the Applicability to address what is desired - requiring backup functionality for operators of "transmission facilities that have a material impact on the reliability of the BES." We suggest the following Applicability for Transmission Operator: 4.1.2. Transmission Operator operating: a) Transmission Facilities at 200 kV or above, or b) non-radial Transmission Facilities above 100 kV, or c) Transmission Facilities operating at voltages lower that those identified in a) or b) that are demonstrated to have a material impact on the reliability of the Bulk Electric System (BES)
ITC	No	The addition to 4.1.2 attempts to address what is really a registration and BES defintion issue. This is not the proper place to these issues. The applicability should be just to the TOP and any limitation to the scope of the TOP should be handled in registration.

Organization	Question 1:	Question 1 Comments:
ISO New England Inc	No	We agree with the drafting team's intent to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV by limiting TOP applicability. However, this is a registration issue and really identifies an issue with the definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration. TOPs operating only radial transmission lines serving load are already excluded from registering per Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Limiting applicability further than this on radial transmission lines in essence redefines the BES and that is not a function of a standard. Please remove the language limiting the applicability.
Ameren	No	We agree with the drafting team's intent to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV by limiting TOP applicability. However, this is a registration issue and really identifies an issue with the definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration. TOPs operating only radial transmission lines serving load are already excluded from registering per Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Limiting applicability further than this on radial transmission lines in essence redefines the BES and that is not a function of a standard. Please remove the language limiting the applicability.
ISO/RTO Council	No	We agree with the drafting team's intent to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV by limiting TOP applicability. However, this is a registration issue and really identifies an issue with the definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration. TOPs operating only radial transmission lines serving load are already excluded from registering per Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Limiting applicability further than this on radial transmission lines in essence redefines the BES and that is not a function of a standard. Please remove the language limiting the applicability.
FirstEnergy Corp.	No	We understand and appreciate the drafting team's intent to eliminate the burden on a Transmission Operator with one radial connection under 200 kV to the BES by refining the applicability to exclude such entities. However, what if there was a single radial 200kV+ line to load not owned by the traditional TO/TOP in the area? Would the owner of the facility be required to have a primary/back-up control center? The applicability section of this standard is not the appropriate place to address these issues. The exclusion for TOPs operating only radial transmission lines serving load is contained in Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Exclusion issues should be vetted and managed in the Rules of Procedure

Organization	Question 1:	Question 1 Comments:
		and the registration processes. The applicability of this standard should point to the functional model entities used in the registration process. It may be simpler to state the applicability as follows related to the TOP: "Transmission Operator of Bulk Electric System (BES) facilities and/or any non-BES facilities, deemed materially important to the BES by the Regional Entity." We believe the SDT should avoid the word "critical" as it may cause confusion with the CIP references to Critical Assets.
Midwest ISO	No	We agree with the drafting team's intent to eliminate the burden on a Transmission Operator that just has a radial connection to the BES under 200 kV by limiting TOP applicability. However, this is a registration issue and really identifies an issue with the definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration. TOPs operating only radial transmission lines serving load are already excluded from registering per Section 501 sub-section 1.2.3 of the NERC Rules of Procedure. Limiting applicability further than this on radial transmission lines in essence redefines the BES and that is not a function of a standard. Please remove the language limiting the applicability. We urge the drafting team to communicate the need to limit applicability of certain requirements in the registration process. This is a broader problem that NERC needs to resolve.
CenterPoint Energy	No	CenterPoint Energy believes the applicability should not include the vague, fill-in-the-blank provision of "?or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System." This provision leaves it open to the whim of a Regional Entity to conjure some rationale to "demonstrate", by whatever means, that these requirements should apply to an otherwise exempt entity. Adding to the vagueness of the language is that it is not clear to whom the Regional Entity would make such a "demonstration". If the Regional Entity "demonstrates" the alleged criticality to itself, the problems with the proposed language should be self-evident to even the most naive proponent. Even if the "demonstration" is to an independent, competent, and trustworthy third party (all of which cannot be assumed without specificity of who the independent third party would be), it is unclear what due process is afforded to otherwise exempt entities to argue the facts asserted by the Regional Entity and to argue the reasonablesss of the vague, undefined "demonstration" criteria used by the Regional Entity to make its assertion of criticality to the reliability of the BES. CenterPoint Energy recommends that this vague, fill-in-the-blank provision be deleted.
PJM Interconnection	No	In 4.1.2, the SDT creates a new class of TOP. This is beyond the Scope of the Standard. 4.1.2 can only apply to current functional entities.

Organization	Question 1:	Question 1 Comments:
Entergy System Planning & Operations (Generation & Marketing)	No	
Response: Based on your comment and many others, the SDT has decided to remove all qualifying language from 4.1.2 and list only "Transmission Operator." We believe, and in addition are convinced by comments received, that the NERC "Statement of Compliance Registry Criteria (Revision 5.0)" and Section 501 (specifically Section 501 1.2.3) of the NERC Rules of Procedure satisfactorily addresses which entities should be registered as a TOP, and therefore, subject to the applicable provisions of this standard. **4.1.2** Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.		
Western Area Power Administration	No	Please define radial/non-radial; Is the definition radial to load, radial to generation, radial to both load and generation?
Response: Because the SDT is removing all qualifying language from 4.1.2 and will be listing only "Transmission Operator" in a revised 4.1.2, the definition of radial/non-radial would be most appropriately addressed through the NERC/Regional Entity registration process, not the standards development process. **4.1.2** Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.		
Santee Cooper	No	In 4.1.2 (Applicability) it is not clear that it is for a radial connection to the BES under 200 kV. There could be differences in what a regional entity deems critical to the reliability of the BES and what a TOP deems critical to the reliability of the BES. Would this allow a Regional Entity to require a TOP with radial facilities deemed critical by the RE to have a backup control center? Suggestion for rewording of 4.1.2: Transmission Operator ?. or radial facilities under 200 kV demonstrated by the Regional Entity to be critical to the reliability of the BES.
Response: Based on the current draft of the standard, an applicable TOP would be required to have backup functionality, not a backup control		

Organization	Question 1:	Question 1 Comments:
center. A TOP could accomplish this with a backup control center, but it could also accomplish this with backup functionality at a third party location, or via contracted services. Due to comments received, we are relying on the NERC registration process to identify the TOPs that would be subject to applicable provisions of the standard. This eliminates the need for qualifying language in 4.1.2 of the standard, and we will list only “Transmission Operator” in the revised 4.1.2. **4.1.2** Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.		
Brazos Electric Power Cooperative, Inc.	No	This new definition basically brings in all TO's that operate transmission lines 100 kV and above given the NERC definition of a Transmission Operator (The entity responsible for the reliability of its 'local' transmission system?) and the emphasis now on Facilities. This new applicability is much broader than the original version and does not eliminate any burden on TO's, it could in fact be quite the opposite. The new applicability does not seem to match the intent of the old language. Taken literally this means that almost all TO's in ERCOT must have a backup control center. In the past we viewed this Standard applied to ERCOT, the one who directs the operation of the BES, not just a 'local' area. If the intent is to require more TO's to have backup control centers we are against this new concept because of the very small probability of ever losing the primary control center. As this happens so infrequently we feel it is not in the best interest of the electric customers to provide something that will have little benefit or any benefit ever. However, if this standard can be assigned to an entity such as ERCOT by each TO to which this applies then we can accept that concept but not all the new language. The last part of 4.1.2 is ambiguous in several ways. How are Facilities 'demonstrated' to be Critical and to whom and under what criteria? This language is not well thought out. The old 4.1.2, while not great, was better than the new one. The use of the word 'control' leads us to believe that the TO who has the final authority or 'control' of the facilities (small 'f', not capital 'F' for facilities), should have the backup control center and thus we assumed this to be ERCOT. We see no reason for this to change.
Response: Based on your comment and many others, the SDT has decided to remove all qualifying language from 4.1.2 and list only “Transmission Operator.” We believe, and in addition are convinced by comments received, that the NERC “Statement of Compliance Registry Criteria (Revision 5.0)” and Section 501 (specifically Section 501 1.2.3) of the NERC Rules of Procedure satisfactorily addresses which entities should be registered as a TOP, and therefore, subject to the applicable provisions of this standard. It is important to understand that this standard applies to TOPs, not TOs that are not also a TOP. In addition, TOPs under the current draft of this standard would be required to have backup functionality, not a backup control center. A TOP could accomplish this with a backup control center, but it could also accomplish this with backup functionality at a third party location, or via contracted services.		

Organization	Question 1:	Question 1 Comments:
Finally, NERC's "Statement of Compliance Registry Criteria (Revision 5.0)" states that a TOP is "an entity that operates an integrated transmission element associated with the bulk power system 100 kV and above ….." This indicates that an entity responsible for only radial transmission lines may not be registered as a TOP, unless such facilities are "defined by the Regional Entity necessary for the reliable operation of the interconnected transmission grid" or if a sub-100 kV facility "is included on a critical facility list that is defined by the Regional Entity." **4.1.2** Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.		
AEP	No	"Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)" needs to be clearly defined. Each regional entity must have a documented process for defining critical facilities.
Response: As the SDT is eliminating the qualifying language for TOPs in 4.1.2 in this standard, we are leaving issues related to determining criticality to the NERC/Regional Entity registration process. This is primarily addressed in the NERC "Statement of Compliance Registry Criteria (Revision 5.0)." The SDT agrees that Regional Entities must have a documented process for determining critical facilities, must clearly identify critical facilities, and notify the facility owners with sufficient time to address applicable standards requirements. **4.1.2** Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.		
Bureau of Reclamation	No	In the applicability of the current draft, the term "Regional Entity" appears. This term is not a NERC defined term, nor is it added for this document, so to whom or what it refers is unclear. What entity(s) are expected to demonstrate the criticality? Is this Entity the RRO, a RC, or some other party? In addition the term "non radial" is not clear, is it non-radial with respect to generation and/or load? The applicability should be for all Transmission Operators, with a provision to allow them to be granted a waiver from their RRO if that TOP can demonstrate why the standard should not apply to them.
Response: Regional Entities (REs) are the entities that NERC has delegated compliance and enforcement responsibilities to through FERC approved delegation agreements. REs essentially are the former Regional Reliability Organizations (RROs) that the industry is familiar with. More information about the eight REs can be found at http://www.nerc.com/page.php?cid=1|9|119. Because the SDT is eliminating the qualifying language for TOPs in 4.1.2 in this standard, we are leaving issues related to radial facilities to the NERC/Regional Entity registration process. All registered entities have the right to challenge the functions they are registered for. A waiver provision is not needed in this standard as the registration process is the appropriate venue for such challenges. **4.1.2** Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the~~		

Organization	Question 1:	Question 1 Comments:
~~Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.		
Puget Sound Energy	Yes	Since there are many differences in size and effect on the BES of the many registered TOPs, there should be a mechanism where the RRO or RC determines the level of risk an entity poses to their area should they lose their control center. Just because a small entity has a line or two that fits the all encompassing definition of BES, does not place the same burden on the system as a large path operator with hundreds of lines. Some entities are large enough where they should have a staffed backup facility. Implementation of costly plans simply due to a registration type that does nothing to increase reliability should be avoided. Costs are passed on to customers. Simply stating it is for reliability does not justify it to them.
Response: The issues identified in your comments are best addressed in the entity registration process and through revisions to the NERC Rules of Procedures and/or the NERC “Statement of Compliance Registry Criteria (Revision 5.0).” The standards development process is not the appropriate place to address the issues you have presented.		
WECC Reliability Coordinator Comment Working Group	Yes	
San Diego Gas and Electric	Yes	
ComEd / Exelon	Yes	
Progress Energy Carolinas, Inc.	Yes	
Southern Company	Yes	

Organization	Question 1:	Question 1 Comments:
Transmission		
Xcel Energy	Yes	
Duke Energy	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Oncor Electric Delivery	Yes	
Independent Electricity System Operator	Yes	
Progress Energy-Florida	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
ReliabilityFirst Corporation	Yes	

Organization	Question 1:	Question 1 Comments:
Bonneville Power Administration	Yes	
Dynegy	Yes	
Response: Thank you for your response.		

2. The SDT has made the transition timeframes equivalent for all applicable entities as shown in Requirement R1.5. Do you agree with this change? If not, please provide specific suggestions for improvement.

Summary Consideration:

The vast majority of the respondents supported the position of the SDT on this issue so no substantial changes have been made to the transition timeframe cited in the standard. However, the following requirements were changed for clarity due to industry comments:

R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours.

R1.6 An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time ~~to~~ to fully implement the backup functionality elements identified in Requirement R1.2~~get backup functionality up and running~~. The Operating Process shall include at a minimum:

R8.1 ~~A demonstration of t~~The transition time between the loss of primary control center functionality and the time to fully implement the backup functionality ~~initiation of backup functionality~~.

Organization	Question 2:	Question 2 Comments:
Entergy System Planning & Operations (Generation & Marketing)	No	It is not apparent as to the basis for this number. Is it arbitrary or based on some technical concern? State as such. A statistical risk analysis would be ideal to determine this allowable time, if a valid model exists. If an arbitrary value is used, then an industry survey or something similar (experts/EPRI) may be appropriate (e.g. EPRI Project RP2473-68)
ISO/RTO Council	No	We agree with and thank the drafting team for making the timeframes equivalent. However, we continue to believe that the new requirement is actually less stringent than the existing requirement. While the new requirement specifies that the backup plan must be implemented in two or less hours, the existing requirement specifies that interim provisions must be made if it will take more than one hour to implement the backup capability. Thus, even if the backup capability is not fully implemented within one hour, the responsible entity still has to have an alternative to operate without the primary control center within an hour. We also question what the 2 hours is based on. Have industry surveys or compliance audit results been utilized that demonstrate that two hours is required to fully implement the back up capability plan instead of the one? We recommend changing the

Organization	Question 2:	Question 2 Comments:
		implementation time back to one hour.
Response: The SDT believes two hours was broad enough to capture the very different business/risk decisions that have been made in the past regarding backup control centers (weighing the value of greater geographic separation over the need for rapid response), but also tight enough for entities to develop mitigations to address the maximum two hour transition period. The SDT believes that the new standard has significantly moved beyond the old standard (original Version 0, R1.8) by requiring immediate management of the risks.		
Progress Energy Carolinas, Inc.	No	Transition Period — Different transition period requirements are needed in order to correlate with the various reasons that a primary control center can be lost. A blanket 2-hour requirement forces a backup site to be within approximately 60–90 miles of the primary site to cover the scenario of the quick loss (“crater”) of the primary center, where offsite personnel must travel from a non-business location to the backup site. However, this distance is insufficient to protect against the loss of both the primary and backup centers due to a major storm, such as a hurricane. Either the transition period needs to be increased to 4 hours, or exceptions are needed for centers located in hurricane-prone areas. Clarification requested as to what constitutes "loss of primary control center functionality" and what constitutes "backup functionality up and running"? Is the functionality to mean at a minimum the aggregate abilities to monitor/maintain frequency, perform AGC, calculate ACE, and perform interchange scheduling (for BA's) and/or for TA's, the minimum aggregate abilities to monitor and control transmission system voltages, power flows, the switching of transmission elements, and ability to respond to IROL's and SOL's violations? Suggest better definition which would identify the minimum as being any one (or all) of the following: – loss of ability to monitor and provide basic tie line control for maintaining the status of all inter-area schedules, –loss of ability to monitor and control critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. – loss of ability to maintain basic voice communication capabilities with other areas.
Progress Energy-Florida	No	Transition Period — Different transition period requirements are needed in order to correlate with the various reasons that a primary control center can be lost. A blanket 2-hour requirement forces a backup site to be within approximately 60–90 miles of the primary site to cover the scenario of the quick loss (“crater”) of the primary center, where offsite personnel must travel from a non-business location to the backup site. However, this distance is insufficient to protect against the loss of both the primary and backup centers due to a major storm, such as a hurricane. Either the transition period needs to be increased to 4 hours, or exceptions are needed for centers located in hurricane-prone areas. Clarification requested as to what constitutes "loss of primary control center functionality" and what constitutes "backup functionality up and running"? Is the functionality to mean at a minimum the aggregate abilities to monitor/maintain frequency, perform AGC, calculate ACE, and perform interchange

Organization	Question 2:	Question 2 Comments:
		scheduling (for BA's) and/or for TO's, the minimum aggregate abilities to monitor and control transmission system voltages, power flows, the switching of transmission elements, and ability to respond to IROLs and SOLs violations? Suggest better definition which would identify the minimum as being any one (or all) of the following: -- loss of ability to monitor and provide basic tie line control for maintaining the status of all inter-area schedules, --loss of ability to monitor and control critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. -- loss of ability to maintain basic voice communication capabilities with other areas.
Response: Regarding the request for the SDT to correlate the transition period to the various reasons a control center could be lost would most likely result in the SDT making a very complex standard that still could not possibly address the number of permutations for the loss of a control center. Regarding clarification as to what constitutes "loss of primary control center functionality," R1.4 specifies that the Operating Plan includes: "Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality." The intention of the SDT is to allow the entity to make the determination that a loss of primary control center functionality has occurred, and when to implement the Operating Plan. The SDT suggests the entity may consider factors, such as, but not limited to: natural disasters, fire, smoke, other inhabitability issues, and control center equipment degradation/failure that precludes continuing operations from the primary control center. Regarding clarification of the term "backup functionality up and running", the SDT believes implementing the modifications specified by Duke Energy in the section below will enhance the standard's clarity.		
Duke Energy	No	We agree that two hours is appropriate for all applicable entities. However we think more clarity is needed on exactly what is required within two hours. R1.5 should be revised as follows: "A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in R1.2 that is less than or equal to two hours". R1.6 should be revised as follows: "An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in R1.2. The Operating Process shall include, at a minimum:". R8.1 should be revised as follows: "A demonstration of the transition time between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in R1.2".
Response: The SDT agrees with the recommended re-wording for R1.5, R1.6, and R8.1 using the reference of R1.2 provides the clarification which is being requested by Progress's comments (above). Thank you for suggesting alternative wording.		

Organization	Question 2:	Question 2 Comments:
R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours. **R1.6** An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time ~~to~~ to fully implement the backup functionality elements identified in Requirement R1.2~~get backup functionality up and running~~. The Operating Process shall include at a minimum: **R8.1** ~~A demonstration of t~~The transition time between the loss of primary control center functionality and the time to fully implement the backup functionality ~~initiation of backup functionality~~.		
Santee Cooper	No	We recommend that R1.5 be changed such that the backup plan be implemented in less than two hours and the backup functionality up and running that is less than three hours. Smaller entities that need a larger physical separation between control centers will need at least three hours to get backup functionality up and running.
Response: The SDT intended the time of 2 hours to be the top most limit for registered entities to have implemented enough of its plan to have restored functionality as described in R1.2. Increasing the time limit is contrary to most of the other comments received.		
Hydro-Québec TransÉnergie (HQT)	No	In the previous version of the Standards, the TOP and BA had a leeway for interim provisions to be included in the plan when extenuating circumstances cause the transition to take longer than two hours (See R8.1 and R8.2 in the redline version). HQT asked to have a similar leeway for the RC. In the current version, that leeway has been removed for all of them. In the answers provided by the SDT, it seems that they assume that facilities for the RC are in another location than that of the BA and TOP. While this might be true for others, for HQT they are all in the same location. HQT propose that that a bullet be added in R1.6.3 that reads: "Interim provisions must be included in the plan when extenuating circumstances cause the transition to take longer than two hours for the RC, TOP and BA"
Response: The SDT never assumed that registered entities that were TOP's, RC's, and BA's were operating these functions from different sites so this notion did not drive the standard's development. The SDT evaluated the possibility of providing for interim provisions; however, interim provisions could result in each registered entity having a different time limit that would make the standard very hard to evaluate. The SDT believes that 2 hours is a reasonable maximum for registered entities to reestablish their critical functionality in order to ensure the reliability of the interconnection. The SDT believes that the new standard has significantly moved beyond the old standard (original Version 0, R1.8) by requiring immediate management of the risks.		
PJM Interconnection	No	The transition timeframe should be defined and justified by the respondent, and be made part of their Operating Plan.

Organization	Question 2:	Question 2 Comments:
Response: The SDT believes the intent of this standard is to reduce the interconnections' risk during periods when registered entities need to utilize their backup control centers; providing each registered entity the flexibility to define its own timeframe may not achieve this intent. Therefore, no change was made.		
Northeast Utilities	Yes	
Midwest ISO	Yes	
Consumers Energy Company	Yes	
WECC Reliability Coordinator Comment Working Group	Yes	
Puget Sound Energy	Yes	
San Diego Gas and Electric	Yes	
ComEd / Exelon	Yes	
Manitoba Hydro	Yes	
Sierra Pacific	Yes	This is an improvement to the Standard.

Organization	Question 2:	Question 2 Comments:
Power Co. (dba NV Energy)		
NPCC	Yes	
Southern Company Transmission	Yes	
Xcel Energy	Yes	
Entergy Services, Inc	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
MRO NERC Standards Review Subcommittee	Yes	
ITC	Yes	
CenterPoint Energy		
Oncor Electric Delivery	Yes	

Organization	Question 2:	Question 2 Comments:
Western Area Power Administration	Yes	
ISO New England Inc	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
ReliabilityFirst Corporation	Yes	
Bonneville Power Administration	Yes	
Dynegy	Yes	
AEP	Yes	The extended transition period increases the criticality of R1.6.
Ameren	Yes	
FirstEnergy Corp.	Yes	We agree that the transition time frames should be equivalent for all applicable entities.
Bureau of Reclamation	Yes	
Response: Thank you for your response.		

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

Summary Consideration: The majority of the responses received supported the SDT VRF assignments and consequently, no changes have been made to the assigned VRF due to industry comments.

Organization	Question 3:	Question 3 Comments:
NPCC	No	We agree with the VRFs for R1 to R8 but not R9. We assess the reliability impact of (R9) failure to come up with a plan 6 months after an entity has experienced a loss of its primary control center or backup capability and expects such loss to last for 6 months or more is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower be assigned to this requirement.
ISO New England Inc	No	We agree with the VRFs for R1 to R8 but not R9. We assess the reliability impact of (R9) failure to come up with a plan 6 months after an entity has experienced a loss of its primary control center or backup capability and expects such loss to last for 6 months or more is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower be assigned to this requirement.
Independent Electricity System Operator	Yes	We agree with the VRFs for R1 to R8 but not R9. We assess the reliability impact of (R9) - that failure to come up with a plan 6 months after an entity has experienced a loss of its primary control centre or backup capability and expects such loss to last for 6 months or more - is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower VRF be assigned to this requirement.
Hydro-Québec TransÉnergie (HQT)	No	We agree with the VRFs for R1 to R8 but not R9. We assess the reliability impact of (R9) failure to come up with a plan 6 months after an entity has experienced a loss of its primary control center or backup capability and expects such loss to last for6 months or more is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower be assigned to this requirement.
Response: The SDT cannot justify reducing the VRF for R9. Going without a plan to restore backup functionality beyond six months could affect "the ability to effectively monitor and control the bulk electric system" as per the definition of a Medium VRF. Therefore, the SDT believes that the proposed VRF is appropriate.		
ITC	No	Per comments made elsewhere, requirement 6 should be part of requirement 1 and therefore have a Medium VRF.

Organization	Question 3:	Question 3 Comments:
Response: Requirement R1 addresses the content of the plan, while Requirement R6 addresses the timeliness of reviews and updates. While it is certainly a judgment call, the SDT believes that Requirement R6 is more of an administrative requirement and hence should continue to have a VRF as currently written.		
ISO/RTO Council	No	R7 should be a sub-requirement of R1. Thus, it should not have a VRF. The VRF for R8 should be lower. Given that the Operating Plan needs to be tested more frequently than annually to ensure that the backup capability is available when it is needed, this requirement is clearly intended to be administrative. Requirement 9 should be removed from the standard. This is, in essence, a requirement for an N-2 contingency. It is such a rare occurrence to operate from a backup center for an extended period of time that this requirement is not needed. If the RC, TOP or BA must operate from their backup center or utilizes their backup capability for an extended period of time, they should work with NERC and the Regional Entity to address the specific situation rather than having a requirement that dictates a time frame. We assess the reliability impact of (R9) failure to come up with a plan 6 months after an entity has experienced a loss of its primary control center or backup capability and expects such loss to last for 6 months or more is lower than any of the other requirements that are assigned a Medium VRF. We therefore suggest a Lower VSL be assigned to this requirement if the requirement is retained.
Midwest ISO	No	R7 should be a sub-requirement of R1. Thus, it should not have a VRF. The VRF for R8 should be lower. Given that the Operating Plan needs to be tested more frequently than annually to ensure that the backup capability is available when it is needed, this requirement is clearly intended to be administrative. Requirement 9 should be removed from the standard. This is, in essence, is a requirement for an N-2 contingency. It is such a rare occurrence to operate from a backup center for an extended period of time that this requirement is not needed. If the RC, TOP or BA must operate from their backup center or utilizing their backup capability for an extended period of time, they should work with NERC and the Regional Entity to address the specific situation rather than having a requirement that dictates a time frame.
Ameren	No	R7 should be a sub-requirement of R1. Thus, it should not have a VRF. The VRF for R8 should be lower. Given that the Operating Plan needs to be tested more frequently than annually to ensure that the backup capability is available when it is needed, this requirement is clearly intended to be administrative. Requirement 9 should be removed from the standard. This is, in essence, is a requirement for an N-2 contingency. It is such a rare occurrence to operate from a backup center for an extended period of time that this requirement is not needed. If the RC, TOP or BA must operate from their backup center or utilizing their backup capability for an extended period of time, they should work with NERC and the Regional Entity to address the specific situation rather than having a requirement that dictates a time frame.
Response: The SDT believes that Requirement R7 is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities.		

Organization	Question 3:	Question 3 Comments:
However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~. The SDT believes that R8 is not administrative. If a plan is not routinely tested, it is likely that weaknesses in the plan will not be identified and remedied. Accordingly we believe that failure to test the plan could affect BES reliability and no change has been made. Requirement R9 is not intended to be an N-2 contingency. It addresses the need for an entity to restore itself to N-1 after it has suffered what we agree is a very rare contingency. We agree that flexibility is required to address the specific situation encountered; that is why the requirement is for a plan to restore functionality instead of actual restoration. The SDT cannot justify reducing the VRF for R9. Going without a plan to restore backup functionality beyond six months could affect "the ability to effectively monitor and control the bulk electric system" as per the definition of a Medium VRF. Therefore, the SDT believes the proposed VRF is appropriate.		
Consumers Energy Company	Yes	
WECC Reliability Coordinator Comment Working Group	Yes	
Puget Sound Energy	Yes	
San Diego Gas and Electric	Yes	
ComEd / Exelon	Yes	
Entergy System Planning & Operations (Generation & Marketing)	Yes	
Manitoba Hydro	Yes	

Organization	Question 3:	Question 3 Comments:
Sierra Pacific Power Co. (dba NV Energy)	Yes	The VRF's and Time Horizons appear to be appropriate.
Progress Energy Carolinas, Inc.	Yes	
Southern Company Transmission	Yes	
Duke Energy	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Oncor Electric Delivery	Yes	
Western Area Power Administration	Yes	
Progress Energy-Florida	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Santee Cooper	Yes	
ReliabilityFirst	Yes	

Organization	Question 3:	Question 3 Comments:
Corporation		
Bonneville Power Administration	Yes	
PJM Interconnection	Yes	
AEP	Yes	
FirstEnergy Corp.	Yes	
Bureau of Reclamation	Yes	
Northeast Utilities	Yes	
Response: Thank you for your response.		

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

Summary Consideration:

There were no major problems expressed with the measures or data retention requirements. However, there were several requests for clarity with request to measures. The SDT has reviewed these and made the following changes based on industry comments:

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.

R7. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.

M1. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format. ~~, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable~~.

M2. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, ~~with evidence of its last issue, located~~ available in its primary control center and at the location supporting backup functionality.

M3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall provide evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities ~~included provisions for the loss of such entity's control functionality in its dated, current, in force Operating Plan for backup functionality~~, ~~with evidence of its last issue,~~ for backup functionality in accordance with Requirement R3.

M4. Each Reliability Coordinator shall provide dated evidence ~~that it has demonstrated~~ that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality in accordance with Requirement R4.

M5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall provide dated evidence ~~that it has demonstrated~~ that ~~it's~~its backup functionality (provided either through a backup control center facility or contracted services) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator, shall have evidence that it's dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, ~~with evidence of its last issue,~~ has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the ~~backup location,~~ capabilities described in Requirement R1~~, or contact information~~ in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have dated evidence that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test~~ed~~ of its ~~dated, current, in force~~ Operating Plan for backup functionality, ~~with evidence of its last issue, and that test results and lessons learned from such testing are noted and incorporated in subsequent revisions of its Operating Plan for backup functionality~~ in accordance with Requirement R8.

R8 VSL

R8.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality, but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented. ~~N/A~~	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the ~~test~~demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.

	or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.		is less than or equal to two hours, and 3) test results were not ~~i~~ documented. ~~N/A~~	

Organization	Question 4:	Question 4 Comments:
Consumers Energy Company	No	M7. calls for "shall have dated evidence that its backup capability does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7." This is subjective as to what that evidence consists of and leaves too much to interpretation. Is a letter stating there is no dependence suffice? Will it suffice regardless of who the auditor is?
Response: Requirement R7 was retained as a concept from the current version of EOP-008 because the SDT believes there is tremendous value in ensuring that backup capabilities not depend upon the primary control center. Measure M7 is an attempt to put terms of measurability around the language of this requirement, without being so prescriptive that we define what that evidence has to be. Measure M7 was revised in an attempt to clarify the intent of the SDT. The SDT cannot supply answers to specific compliance questions. **M7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have dated evidence that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality in accordance with Requirement R7.		
Puget Sound Energy	No	M.3 - There needs to be clarification in either the requirement or the measure as to the definition of "directing", "entity" and "control functionality". Was this intended to be the TOP that is acting as a host for a DP, or say a GOP? Does the loss of functionality mean a RTU being down now must be addressed in the loss of control center plan for the TOP? Does this even need to be a requirement since R.5 is so vague and encompassing? Why just the TOP and not BA's that are providing regulation services of acting as a host to others? The measurement and requirement are open to interpretation. Both need to be clear, concise and measurable. M.6 - The requirement and measure ask for approval. What level of approval does the SDT expect for this? If the SDT does not feel the need to specify, then why have it.

Organization	Question 4:	Question 4 Comments:
		M.7 - The measure requires dated evidence of a negative statement. Proving a negative in an audit is not easy. Could a statement in the current, dated Operating Plan stating it does not rely on the primary facility be sufficient evidence? I know the SDT does not determine what is acceptable to an auditor, but measures asking for dated proof that something does not exist, did not happen or are not dependent should be avoided. Will I have to provide dated evidence that I did not lose my primary capability for six months in M.9 as well? M.8 Providing evidence that the Operating Plan and backup functionality were tested is definitely needed. The current wording of the requirement and measure could be interpreted as each version of the plan must be tested. If a test is done, and the plan is subsequently updated with lessons learned as required in R8.3, the new dated, current, in force plan would not have evidence of being tested. I know this is petty and just semantics, but compliance people may take it literally.
Response: M3 – See response in question 7 related to suggested changes to R3. Both Requirement R3 and Measure M3 were revised to clarify the intent of the SDT. **R3** – Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~. **M3**. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall provide evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities ~~included provisions for the loss of such entity's control functionality in its dated, current, in force Operating Plan for backup functionality~~, ~~with evidence of its last issue,~~ for backup functionality in accordance with Requirement R3.. M6 – The SDT did not specify who should approve the procedure because entities are structured differently, and may already have processes in place for the approval of operating procedures. Approval is required to ensure that the procedures have the authority of the operating level management or higher to enforce the implementation of the procedure. M7 & M9 – The SDT feels that the measure is clear and that the proof is not burdensome. No change made. M8 – The SDT can understand how that would be a possible interpretation of M8 and has made wording changes for clarity. **M8.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test~~ed~~ of its ~~dated, current, in force~~ Operating Plan for backup functionality, ~~with evidence of its last issue, and that test results and lessons learned from such testing are noted and incorporated in subsequent revisions of its Operating Plan for backup functionality~~ in accordance with Requirement R8.		
Progress Energy	No	What is purpose of requiring Operating Plans to be retained for prior 3 years? It should be satisfactory to maintain current active plan with retention revisions of last full calendar year unless there has been a compliance violation identified by the

Organization	Question 4:	Question 4 Comments:
Carolinas, Inc.		Regional Compliance entity. R8 — Does a test in January of one year followed by a test in December of the following year meet the requirement of an “annual” test? If not, the wording here should match Violation Security Levels section D.2.R8. M5 — Does this require a document detailing each requirement of all Reliability Standards along with a description of how each is satisfied at the backup (similar to an audit response)? If not, what else can satisfy this measure? M7 — Does this require a document detailing each requirement of all Reliability Standards along with a description of how it is satisfied at the backup (similar to an audit response) without utilizing equipment at the primary? If not, what else can satisfy this measure? D.1.4, 5th bullet (related to M5) — Does this require a demonstration of adequate backup functionality to be repeated and documented at least once between compliance audits? This measure is not needed since R8/M8 requires an annual test with documentation.D.2. R8, Lower Level — States that a violation occurs if subsequent tests occur more than 12 months apart. Section B.R8 states that an annual test shall be conducted. Unless the term “annual” is defined as “every 12 months” in a reference document, these descriptions must match.
Progress Energy-Florida	No	What is purpose of requiring Operating Plans to be retained for prior 3 years? It should be satisfactory to maintain current active plan with retention of last full calendar year unless there has been a compliance violation identified by the Regional Compliance entity. R8 — Does a test in January of one year followed by a test in December of the following year meet the requirement of an “annual” test? If not, the wording here should match Violation Security Levels section D.2.R8. M5 — Does this require a document detailing each requirement of all Reliability Standards along with a description of how each is satisfied at the backup (similar to an audit response)? If not, what else can satisfy this measure? M7 — Does this require a document detailing each requirement of all Reliability Standards along with a description of how it is satisfied at the backup (similar to an audit response) without utilizing equipment at the primary? If not, what else can satisfy this measure? D.1.4, 5th bullet (related to M5) — Does this require a demonstration of adequate backup functionality to be repeated and documented at least once between compliance audits? This measure is not needed since R8/M8 requires an annual test with documentation. D.2.R8, Lower Level — States that a violation occurs if subsequent tests occur more than 12 months apart. Section B.R8

Organization	Question 4:	Question 4 Comments:
		states that an annual test shall be conducted. Unless the term “annual” is defined as ?every 12 months? in a reference document, these descriptions must match.

Response: Data retention is an aspect of each standard. The intent of the SDT is to ensure that evidence and copies of the Operating Plan be retained for review by the compliance audit team since the last compliance audit, currently three years, although due to scheduling of audits, it is possible that the audit period may extend beyond 36 months. That is why the team recommends retaining data for three previous years, plus the current year.

R8. As the standard is written the annual test could be performed at any point during that year, not just within twelve months of the previous year’s test.

M5. The SDT anticipates that the Operating Plan including the elements of R5 would be sufficient to meet the requirement of M5 but the SDT can’t answer for what an auditor might require.

M7. The measure is that evidence will be provided which could include a review, study, report, or some other appropriate type of evidence that the backup capabilities do not share a common point of failure with the primary control center. The type of document described in your comment is another type of evidence which could be used. The SDT cannot supply answers to specific compliance questions.

D1.4. This is a data retention requirement that the dated evidence showing compliance with R5, and measured according to M5 be retained since the entity’s last compliance audit. It does not impose any additional demonstrations of backup functionality.

R8 VSL for lower severity level violation: Agreed. As the standard is written the annual test could be performed at any point during that year, not just within twelve months of the previous year’s test. R8 VSL has been changed for clarity.

R8 VSL

R8.		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality, but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation~~	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours,	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the ~~test~~demonstration was for less than two continuous hours, 2) it has failed to	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality

Organization	Question 4:	Question 4 Comments:
		~~or test operations~~ for less than two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~. | or 3) test results were not documented. ~~N/A~~ | demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented. ~~N/A~~
Entergy Services, Inc	No	M4 and M5 contain the phrase "shall provide dated evidence that it has demonstrated that it has a (BCC)?" Measures should not include requirements. These measures include new requirements and unspecified additional measures on several unspecified entities. These measures include a requirement that the RC, BA or TOP "demonstrate" BCC functionality to some unspecified entity and then that unspecified entity must "provide dated evidence" to the RC, BA and TOP so the RC, BA and TOP can provide that "dated evidence" for evidence of compliance. This requirement for demonstration to, and approval by, some unspecified entity is not in the NERC standards. We suggest the demonstration aspect of these measures be deleted and the measures be changed to: "M4. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility ??." "M5. Each Balancing Authority and applicable Transmission Operator shall provide dated evidence that it's backup functionality?"

Response: The intent of M4 and M5 is just that an entity have dated evidence that it met R4 and R5 respectively. The wording of M4 & M5 have been changed for clarity.

M4. Each Reliability Coordinator shall provide dated evidence ~~that it has demonstrated~~ that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality in accordance with Requirement R4.

M5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall provide dated evidence ~~that it has demonstrated~~ that ~~it's~~its backup functionality (provided either through a backup control center facility or contracted services) includes monitoring, control, logging, and alarming sufficient for maintaining

Organization	Question 4:	Question 4 Comments:
compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R5.		
Duke Energy	No	This standard uses the terms "control center", "capability", "facility" and "functionality" somewhat interchangeably. We believe the standard should consistently use the term "functionality" in the Requirements, Measures and Data Retention (see detailed comment #7 below). The Data Retention requirements are onerous and need further review. For example, there is no need to retain three years of old Operating Plans for backup functionality.
Response: The SDT has attempted to be consistent in its use of these terms. The terms capability and functionality are used instead of facilities designated as control centers to denote that the Operating Plan does not just have to provide for an alternate physical space for control center personnel to work from, but also the provision for the functionality required of a registered entity to meet the standards, such as monitoring and control. The term functionality refers to the functions that are required to be performed by a registered entity, while capability refers to an entities ability to perform that function. So the plan needs to provide the capability for each function to be met. Data retention is an aspect of each standard. The intent of the SDT is to ensure that evidence and copies of the Operating Plan be retained for review by the compliance audit team since the last compliance audit, currently three years, although due to scheduling of audits, it is possible that the audit period may extend beyond 36 months. That is why the team recommends retaining data for three previous years, plus the current year.		
Electric Reliability Council of Texas, Inc.	No	M5: change "it's" to "its" M7: delete if is made part of R1 M8: this measure and the related data retention requirement (Bullet 8) imply that testing must occur immediately on changing the Plan. Also change "such testing" to "previous testing" M9: change if R9 is changed Data Retention Bullet 3: this will be hard to do until the standard has been in place for several years. It may be deleted if R3 is changed or removed. Data Retention Bullet 6: this will be hard to do until the standard has been in place for several years. Data Retention Bullet 7: delete if R7 is rolled into R1
Response: M5 change 'it's' to 'its'. The SDT agrees to this change. **M5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall provide dated evidence ~~that it has demonstrated~~ that ~~it's~~its backup functionality (provided either through a backup control center facility or contracted services) includes monitoring, control, logging, and alarming sufficient for maintaining		

Organization	Question 4:	Question 4 Comments:
compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R5. M7 – The SDT did not roll Requirement R7 into Requirement R1 so Measure M7 remains in place. The SDT believes that Requirement R7 is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.. M8 – The SDT can understand how that would be a possible interpretation of M8 and has made wording changes for clarity. **M8.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test~~ed~~ of its ~~dated, current, in force~~ Operating Plan for backup functionality, ~~with evidence of its last issue, and that test results and lessons learned from such testing are noted and incorporated in subsequent revisions of its Operating Plan for backup functionality~~ in accordance with Requirement R8. M9 – The SDT did not change Requirement R9 as suggested so there is no need to change here. Since Requirement R7 was not rolled into Requirement R1, there is no reason to delete Data Retention 7. The SDT believes that Requirement R7 is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.		
MRO NERC Standards Review Subcommittee	No	M1, M2, M3, M6, states that Entities shall have a "dated, current, in force Operating Plan?", The SDT is placing a measurement that is not contained in the Requirement. M4, M5, M7, states that Entities shall provide "dated evidence?", The SDT is placing a measurement that is not contained in the Requirement.
Response: Requirement R6 contains language that requires the backup plan to be annually reviewed and approved, and update and approval for any changes to be accomplished within 60 days of changes in backup location, capability or contact information. Requirement R8 also includes the requirement for an annual test of its Operating Plan. The terms dated, current, and in force refer to the timing requirements stated in Requirement R6, that the Operating Plan for backup or redundant functionality be		

Organization	Question 4:	Question 4 Comments:
dated to determine when it became effective, current, and in force, to denote that it is the version of the plan that is approved, and has been updated to include any changes in location, capability, or contact information. The measures in this case do not add to the requirements, but rather make the requirements clearly measurable. The SDT feels that 'dated evidence' is needed in the measurements of the various requirements to demonstrate for an auditor that the entity was in compliance for the period of time since the last audit. If, for instance, test results are provided with no dates as to when the test was performed, the auditors would have no way of knowing whether or not the requirement, such as R8 which requires annual testing of the Operating Plan, was met.		
ITC	No	Suggest replacing the words "current, in-force" with "approved" for clarity in several of the Measures. The implication of "approved" is that an auditor would be able to see a signature of approval of the Plan. Measure 7 evidence would not be easy to provide since you trying to prove a negative - that you don't do something. An auditor could not practically verify that the technical backup capability does not depend on the primary control center. Per comments elsewhere, the associated requirement should be removed and defer to requirement 1.
Response: The term 'approved' is included to address the authority of the plan, whereas the terms 'current and in-force' have more to do with ensuring the version of the plan which is provided to operating personnel is the version of the plan which has been most recently reviewed and distributed to the intended audience. M7 – In this case, the SDT is not asking an entity for proof that something didn't happen. Rather, the measure is that evidence should include a review, study or report, or some other appropriate type of evidence that the backup capabilities do not share a common point of failure with the primary control center, which can be done and documented.		
Western Area Power Administration	No	These measures should be consistent with other existing data retention measures that have already been approved (3 years worth of data). Suggestion is to have the current year and two previous years worth of data.
Bureau of Reclamation	No	These measures should be consistent with other existing data retention measures that have already been approved.
Xcel Energy	No	Data retention should be 3 years.
Response: Data retention is an aspect of each standard. The intent of the standards drafting team is to ensure that evidence and copies of the Operating Plan be retained for review by the compliance audit team since the last compliance audit, currently three years, although due to scheduling of audits, it is possible that the audit period may extend beyond 36 months. That is why the team recommends retaining data for three previous years, plus the current year.		

Organization	Question 4:	Question 4 Comments:
Brazos Electric Power Cooperative, Inc.	No	It seems excessive to retain each and every change to these documents and to note that they be 'an approved' plan. We think more emphasis should be placed on having the backup and demonstrating its readiness instead of worrying about documenting everything. No real suggestion for improvement other than to remove some of the unnecessary documentation burdens and language. Perhaps just delete all the lower risk items.
Response: While the purpose of the standard is to ensure that adequate backup capability exists, the Operating Plan is an integral part of verifying that backup capability. Documentation and measures that are appropriate for audit are an important part of this verification. The requirements for approval and retention are needed to ensure that adequate review and authorization are given to the Operating Plan and that the entity retains sufficient documentation to demonstrate compliance for the period covered by the audit. The SDT does not consider the retention of this data to be unnecessary.		
PJM Interconnection	No	Changes need to be made to address the primary/backup language (see 7 below). Additionally, data retention requirements are far too voluminous. There should only be one version (current) in the Control Center. Requiring 3 years worth of outdated plans in the control room, accessible to the operators, may result in mis-operations.
Response: It is not the intention of the SDT that three years of outdated plans be maintained in the control room. Rather the requirement to maintain former versions of the plan is for audit purposes only. Only the current version of the plan should be provided to operating personnel for implementation**.**		
Ameren	No	Measures 1, 2, 3, 6, and 8 require dated, current, in force Operating Plan but there is no time requirement in the associated requirements. Measures should not add to the requirements. What does current really mean? How would the compliance auditor know if the Operating Plan is current given that the requirement does not mention date or time? We suggest removing the term in force because it does not add anything to the requirement. Why would the responsible entity supply an Operating Plan to the compliance auditor that wasn't in force? Measures 1, 2, 3, 6, and 8 also state that evidence of the last issue of the Operating Plan is required. There is nothing in the associated requirements about issuing. Thus again the measures are adding to the requirements but should not. To whom is the Operating Plan required to be issued in the Measures? Part of the issue with Measure 6 is that its associated requirement really should be a sub-requirement of requirement 1. This would solve some of the issues with Measure 1. A large part of the issue with Measures 2, 3, 6, and 8 appear to be overuse of copy and paste. The only requirement associated with these measurements that really needs a dated Operating plan as evidence is requirement 1 but as the requirement is currently written it does not require the Operating Plan to have a date. Measure 7 should not include a requirement for dated evidence. What is really needed is that the Operating Plan evidence presented should have a date and the Operating Plan should be verified to not depend on the primary control center. The compliance auditors could not practically verify that the backup capability or backup control center does not depend on the primary control center. Thus, the requirement associated with Measure 7 is really a sub-requirement of requirement 1.Measurement 9 should not require the RC, BA, and TOP to have evidence that a plan has been submitted to its Regional Entity when it loses its primary control center or backup capability or backup control center because the Regional Entity is the Compliance

Organization	Question 4:	Question 4 Comments:
		Enforcement Authority. The Regional Entity will know when the plan is received.
FirstEnergy Corp.	No	Measures 1, 2, 3, 6, and 8 require a dated Operating Plan but there is nothing in the associated requirements that states the plan shall contain an effective date. The requirements section of the standard should cover all of the expectations Measures should not add to the requirements. We believe adding a subrequirement to R1 that requires the plan have an effective date, would provide the appropriate source documents to substantiate compliance for all requirements associated with the Operating Plan. Also, with the span of time that elapses between each compliance audit, the drafting team should consider whether the measures section should include statements to retain copies of revisions to the plan for the specified retention period as evidence of compliance. The measures could be simplified by not repeating text that has already been stated, so that the main point is clearly evident. For example in Measure M2 the intent of the requirement and measure is ensure a valid copy of the Operating Plan is located at both the primary and back-up centers. Therefore it may be more concise to say: "Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have evidence of a vaild Operating Plan, meeting R1/M1, is in force and located at its primary and back-up operating centers. It is suggested that the SDT consider this advice/recommendation throughout all measures to improve readability so that readers can quickly understand what is needed. There should be no need to re-peat text from other requirements/measures already covered within the standard.
ISO/RTO Council	No	Measures 1, 2, 3, 6, and 8 require dated, current, in force Operating Plan but there is no time requirement in the associated requirements. Measures should not add to the requirements. What does current really mean? How would the compliance auditor know if the Operating Plan is current given that the requirement does not mention date or time? We suggest removing the term in force because it does not add anything to the requirement. Why would the responsible entity supply an Operating Plan to the compliance auditor that wasn't in force? Measures 1, 2, 3, 6, and 8 also state that evidence of the last issue of the Operating Plan is required. There is nothing in the associated requirements about issuing. Thus again the measures are adding to the requirements but should not. To whom is the Operating Plan required to be issued in the Measures? Part of the issue with Measure 6 is that its associated requirement really should be a sub-requirement of requirement 1. This would solve some of the issues with Measure 1. A large part of the issue with Measures 2, 3, 6, and 8 appear to be overuse of copy and paste. The only requirement associated with these measurements that really needs a dated Operating plan as evidence is requirement 1 but as the requirement is currently written it does not require the Operating Plan to have a date. Measure 7 should not include a requirement for dated evidence. What is really needed is that the Operating Plan evidence presented should have a date and the Operating Plan should be verified to not depend on the primary control center. The compliance auditors could not practically verify that the backup capability or backup control center does not depend on the primary control center. Thus, the requirement associated with Measure 7 is really a sub-requirement of requirement 1.Measurement 9 should not require the RC, BA, and TOP to have evidence that a plan has been submitted to its Regional Entity when it loses its primary control center or backup capability or backup control center because the Regional Entity is the Compliance Enforcement Authority. The Regional Entity will know when the plan is received.

Organization	Question 4:	Question 4 Comments:
Midwest ISO	No	Measures 1, 2, 3, 6, and 8 require dated, current, in force Operating Plan but there is no time requirement in the associated requirements. Measures should not add to the requirements. What does current really mean? How would the compliance auditor know if the Operating Plan is current given that the requirement does not mention date or time? We suggest removing the term in force because it does not add anything to the requirement. Why would the responsible entity supply an Operating Plan to the compliance auditor that wasn't in force? Measures 1, 2, 3, 6, and 8 also state that evidence of the last issue of the Operating Plan is required. There is nothing in the associated requirements about issuing. Thus again the measures are adding to the requirements but should not. To whom is the Operating Plan required to be issued in the Measures? Part of the issue with Measure 6 is that its associated requirement really should be a sub-requirement of requirement 1. This would solve some of the issues with Measure 1. A large part of the issue with Measures 2, 3, 6, and 8 appear to be overuse of copy and paste. The only requirement associated with these measurements that really needs a dated Operating plan as evidence is requirement 1 but as the requirement is currently written it does not require the Operating Plan to have a date. Measure 7 should not include a requirement for dated evidence. What is really needed is that the Operating Plan evidence presented should have a date and the Operating Plan should be verified to not depend on the primary control center. The compliance auditors could not practically verify that the backup capability or backup control center does not depend on the primary control center. Thus, the requirement associated with Measure 7 is really a sub-requirement of requirement 1. Measurement 9 should not require the RC, BA, and TOP to have evidence that a plan has been submitted to its Regional Entity when it loses its primary control center or backup capability or backup control center because the Regional Entity is the Compliance Enforcement Authority. The Regional Entity will know when the plan is received.

Response: The SDT understands that the use of several adjectives to describe the timeliness and authorization of the Plan may seem superfluous, but believes that each of these words are needed to capture the expectation that the Operating Plan be the most recent version, with the effective date noted, with appropriate approval authority, and be the one that is currently in effect.

R1 and R2 – The SDT has modified the requirements to add a timing factor. The other requirements already included a timing factor.

In response to these comments, M1, M2, M3, M6, and M8 have been revised to remove the 'evidence of issue' wording.

M1. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format. ~~, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable~~.

M2. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, ~~with evidence of its last issue, located~~ available in its primary control

Organization	Question 4:	Question 4 Comments:
center and at the location supporting backup functionality. **M3**. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall provide evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities ~~included provisions for the loss of such entity's control functionality in its dated, current, in force Operating Plan for backup functionality~~, ~~with evidence of its last issue,~~ for backup functionality in accordance with Requirement R3. **M6**. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator, shall have evidence that it's dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, ~~with evidence of its last issue,~~ has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the ~~backup location,~~ capabilities described in Requirement R1~~,~~ ~~or contact information~~ in accordance with Requirement R6. **M8.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test~~ed~~ of its ~~dated, current, in force~~ Operating Plan for backup functionality, ~~with evidence of its last issue, and that test results and lessons learned from such testing are noted and incorporated in subsequent revisions of its Operating Plan for backup functionality~~ in accordance with Requirement R8. R1 & R6: The SDT does not consider the requirement and associated measure for annual review and approval, or review and approval within 60 days of changes being made to be redundant with Requirement R1 and its sub-requirements which contain the minimum set of attributes to be included in the Operating Plan for redundant or backup functionality. The intent of M7 is that the entity provides evidence that its backup functionality does not depend upon the primary control center for any functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7. The intent of Requirement R9 is not to simply notify the Reliability Assurer but to provide the entity that has suffered the failure a 6 month window in which to create a plan without being in non-compliance of the basic requirements in this standard. Without Requirement R9, the entity that has suffered a loss is technically out of compliance with several other requirements in this standard.		
ISO New England Inc	No	We do not agree with some of the requirements (see our comments under Q7) and hence some Measures may need to be revised if the SDT agrees with any of our suggested changes to the requirements.
Independent Electricity System Operator	Yes	We do not agree with some of the requirements (see our comments under Q7) and hence some Measures may need to be revised if the SDT agrees with any of our suggested changes to the requirements.
NPCC	Yes	We do not agree with some of the requirements (see our comments under Q7) and hence some Measures may need to be

Organization	Question 4:	Question 4 Comments:
		revised if the SDT agrees with any of our suggested changes to the requirements.
Hydro-Québec TransÉnergie (HQT)	No	We do not agree with some of the requirements (see our comments underQ7) and hence some Measures may need to be revised if the SDT agrees with any of our suggested changes to the requirements.
Response: See the comments provided in Question 7.		
WECC Reliability Coordinator Comment Working Group	Yes	
San Diego Gas and Electric	Yes	
ComEd / Exelon	Yes	
Entergy System Planning & Operations (Generation & Marketing)	Yes	
Manitoba Hydro	Yes	
Sierra Pacific Power Co.	Yes	

Organization	Question 4:	Question 4 Comments:
(dba NV Energy)		
Southern Company Transmission	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Santee Cooper	Yes	
ReliabilityFirst Corporation	Yes	
Bonneville Power Administration	Yes	
AEP	Yes	
Northeast Utilities	Yes	
Response: Thank you for your response.		

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

Summary Consideration:

Numerous comments were received from industry on the VSLs. The SDT reviewed these comments, some of which disagreed with each other, and has made corresponding changes in the VSLs for EOP-008-1. The following changes have been made due to industry comments:

R1 Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a~~n~~ current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This Operating Plan for backup functionality shall include the following at a minimum:

R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours.

R2 Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a copy of its current Operating Plan for backup functionality ~~located~~ available ~~in~~at its primary control center and at the location supporting backup functionality.

M1. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format. ~~, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable~~.

M2 Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, ~~with evidence of its last issue,~~ ~~located~~ available ~~in~~at its primary control center and at the location supporting backup functionality.

M8. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test~~ed~~ of its ~~dated, current, in force~~ Operating Plan for backup functionality, ~~with evidence of its last issue, and that test results and lessons learned from such testing are noted and incorporated in subsequent revisions of its Operating Plan for backup functionality~~ in accordance with Requirement R8.

R1 VSL

R1	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing one of the sub-	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing two of the sub-	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing three or more of	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator does not have a~~n~~ current Operating Plan for backup functionality.

	requirements or the plan ~~is~~ does not ~~dated with evidence~~reflect the date of its last ~~issue~~issuance.	requirements.	the sub-requirements or is not compliant with Requirement R1.5.	
R2 VSL				
R2	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality ~~but the plan is not located~~ available ~~in~~ at ~~one~~all of its control locations but at one location it is not the current plan.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality ~~but the plan is not located~~ available ~~in~~at ~~either~~ all of its control locations but at all locations it is not the current plan.	N/A	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality but no version of the plan is available at all of its control locations.
R3 VSL				
R3	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Lower VRF ~~for 10% or less of its~~	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Medium VRF ~~for more than 10% and less~~	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a High VRF~~for more than 25% of its~~	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of any such entity's control functionality in its Operating Plan for backup functionality.

	~~applicable entities~~ in its Operating Plan for backup functionality.	~~than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	~~applicable entities~~ in its Operating Plan for backup functionality.	

R4 VSL

R4	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.

R5 VSL

R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~,~~ ~~or its evidence is not dated.~~	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.
R6 VSL				
R6	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator, has evidence that it's dated, current, in force Operating Plan for	~~The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for~~	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator, has evidence that it's dated, current, in force Operating Plan for	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator, does not have evidence that it's dated, current, in force Operating

	backup functionality, ~~with evidence of its last issue,~~ was reviewed and approved but it was not done in one calendar year ~~more than twelve calendar months and less than or equal to fifteen calendar months~~ or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes ~~to the backup location,~~ capabilities described in Requirement R1~~, or contact information~~.	~~backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in more than two calendar years fifteen calendar months or that it was updated more than ninety calendar days after any changes to the backup location, capabilities, or contact information.~~ N/A	backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in two calendar years or more or that it was updated more than ninety calendar days after any changes to the capabilities described in Requirement R1.	Plan for backup functionality was reviewed and approved.

R7 VSL

R7	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator's ~~dated~~ evidence does not demonstrate~~shows~~ that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for the functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality.

R8 VSL

R8	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality, but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented.~~N/A~~	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented. ~~N/A~~	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.

Organization	Question 5:	Question 5 Comments:
Puget Sound Energy	No	R.3 Since the terms of this requirement and measure are not clearly defined, there is no clear way to determine what percentage was met. R.5 What mechanism will be used to determine the percentage of standards can be or could be met?

Response: The BFSDT agrees and has modified Requirements R3 and R5 VSL to better address the intent of the SDT and to remove the reliance on a percentage calculation.

R3 VSL

R3		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Lower VRF ~~for 10% or less of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Medium VRF ~~for more than 10% and less than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a High VRF~~for more than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of any such entity's control functionality in its Operating Plan for backup functionality.

R5 VSL

Organization	Question 5:	Question 5 Comments:			
R5		The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~,~~ ~~or its evidence is not dated.~~	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.
San Diego Gas and	No	We would like to see additional consistency used between the Requirements verbiage and the Violation Severity Level table verbiage, particularly with respect to R8 (although this same terminology appears elsewhere as well). The Requirements			

Organization	Question 5:	Question 5 Comments:
Electric		verbiage for R8 uses the term "annual" in the description when referring to testing, whereas the VSL table refers to a period of "12 calendar months." In discussing the terminology with others, there seems to be a difference of opinion of the definition of the word "annual" when it comes to NERC compliance. Some people think that the particular requirement can be fulfilled anytime within a particular calendar year (one year in July and the following year in September and the following year in May, etc.), whereas others believe that an August 1 test date in one year means that the same testing must be completed before August 1 in the following year to remain in compliance. The issue with the latter interpretation of "annual" is that the requirement will suffer from date creep every year, as the entity completes the compliance requirement in advance of the prior year. Over time, this date creep will ultimately cause entities to have to perform testing and other requirements at times of the year when we don't want to do them (i.e. summer periods) or do them too far in advance. We believe the requirement should be spelled out specifically so the definition is crystal clear (i.e., every 11 months plus or minus 30 days).

Response: The SDT agrees and has clarified the language in the VSL for Requirement R8 to make it consistent with the requirement that the test is an annual test that is conducted at any time in a calendar year.

R8 VSL

R8		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality, but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than two continuous hours,	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the ~~test~~ demonstration was ~~through actual implementation or test operations~~ for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not ~~incorporated~~	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.

Organization	Question 5:	Question 5 Comments:

		2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.	results were not documented. ~~N/A~~	documented. ~~N/A~~	

Organization	Question 5:	Question 5 Comments:
Sierra Pacific Power Co. (dba NV Energy)	No	In R2 Lower, we recommend that the VSL language be amended to strike "located in one of its control locations" and replace with "available to Operators at one of either the primary or backup control centers" and in R2 Moderate, amend to remove "located in either of its control locations" and replace with "available to Operators at any of its control locations". In R5, it appears that the degree of severity will be nearly impossible to determine. The VSL language calls for a determination of exactly what percentage of the Reliability Standards can be complied with from the backup center. While we don't have a specific suggestion, we believe that the Auditors will have a very difficult time making a determination with the VSL's as written. In R7, there is only one VSL and it is "severe". The degree of violation here must depend upon the level of dependency that the backup functionality has upon the primary control center and the number and relative importance of the functions for which that dependency exists. We respectfully disagree with the exclusion of Lower, Moderate and High VSL's and the classification of any violation as being "severe" for this Requirement.

Response: R2: It is the intent of the SDT to allow electronic or hardcopy of the plan to meet Requirement R2 and it has modified Measure M2 and the R2 VSL accordingly. The SDT also agrees with the notion of the plan being 'available at' rather than 'located at' in order to be consistent with the change to accommodate electronic access and has modified Requirement R2 VSL accordingly

R2 Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a copy of its current Operating Plan for backup

Organization	Question 5:	Question 5 Comments:

functionality ~~located~~ available ~~in~~at its primary control center and at the location supporting backup functionality.

M2 Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, ~~with evidence of its last issue, located~~ available ~~in~~at its primary control center and at the location supporting backup functionality.

R2 VSL

R2		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality ~~but the plan is not located~~ available ~~in~~ at ~~one~~all of its control locations but at one location it is not the current plan.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality ~~but the plan is not located~~ available ~~in~~at ~~either~~ all of its control locations but at all locations it is not the current plan.	N/A	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality but no version of the plan is available at all of its control locations.

R5: The SDT agrees and has modified the VSL for R5 accordingly.

R5 VSL

R5		The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with

Organization	Question 5:	Question 5 Comments:

	~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	~~r~~Requirement R5.

R7: The SDT discussed this issue extensively and determined that there is not any definable level of dependence between the primary and backup control functionality that would have a lower severity level, and as such did not define Lower, Moderate or High VSL for Requirement R7. The SDT did change the wording of the VSL in an attempt to provide clarity.

R7 VSL

R7	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator's ~~dated~~ evidence does not demonstrate~~shows~~ that its primary and backup

Organization	Question 5:	Question 5 Comments:
		capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for the functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality.
Progress Energy Carolinas, Inc.	No	Reference section D.2 Violation Severity Levels R5 -- there are specific percentages stated therein, how are they calculated? Is it per standard or per individual requirement and sub-requirements?
Progress Energy-Florida	No	Reference section D.2 Violation Severity Levels R5 — there are specific percentages stated therein, how are they calculated? Is it per standard or per individual requirement and sub-requirements?

Response: The SDT agrees and has modified the VSL accordingly.

R5 VSL

R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with

Organization	Question 5:	Question 5 Comments:
		~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~ ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF. ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF. ~~r~~Requirement R5.
NPCC	No	R2: It requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guidelines. R4: The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. R5: Same comment as in (ii) except the entities are the BAs and applicable TOPs. R6: There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not review and if necessary update its plan after 18 months, or 120 calendar days after changes were made to the backup capability; a Severe for failing to review and if necessary update its

Organization	Question 5:	Question 5 Comments:
		plan for a longer time period or not at all.
ISO New England Inc	No	R2: It requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guidelines. R4: The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. R5: Same comment as in (ii) except the entities are the BAs and applicable TOPs. R6: There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not review and if necessary update its plan after 18 months, or 120 calendar days after changes were made to the backup capability; a Severe for failing to review and if necessary update its plan for a longer time period or not at all.
Independent Electricity System Operator	No	R2: It requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guideline. R4: The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. R5: Same comment as in (ii) except the entities are the BAs and applicable TOPs. R6: There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not update its plan after 18 months or 120 calendar days after changes were made to the backup capability; a Severe VSL may be assigned for failing to update its plan for a longer time period or at all.

Organization	Question 5:	Question 5 Comments:
Hydro-Québec TransÉnergie (HQT)	No	R2: It requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guidelines. R4: The Severe level should include a condition that the RC provides less than 70%of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. R5: Same comment as in (ii) except the entities are the BAs and applicable TOPs. R6: There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not review and if necessary update its plan after 18 months, or 120 calendar days after changes were made to the backup capability; a Severe for failing to review and if necessary update its plan for a longer time period or not at all.

Response: R2: It is the intent of the SDT to allow electronic or hardcopy of the plan to meet Requirement R2 and it has modified Measure M2 and the R2 VSL accordingly. The SDT also agrees with the notion of the plan being 'available at' rather than 'located at' in order to be consistent with the change to accommodate electronic access and has modified Requirement R2 VSL accordingly

R2 Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a copy of its current Operating Plan for backup functionality ~~located~~ available ~~in~~at its primary control center and at the location supporting backup functionality.

M2 Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, ~~with evidence of its last issue, located~~ available ~~in~~at its primary control center and at the location supporting backup functionality.

R2 VSL

R2		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality	N/A	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality

Organization	Question 5:	Question 5 Comments:			
		~~but the plan is not located~~ available ~~in~~ at ~~one~~all of its control locations but at one location it is not the current plan.	~~but the plan is not located~~ available ~~in~~at ~~either~~ all of its control locations but at all locations it is not the current plan.		but no version of the plan is available at all of its control locations.
R4/R5: The SDT agrees and has modified the VSL for Requirements R4 and R5 to remove reliance on percentages. **R4 VSL**					
R4		The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.

Organization	Question 5:	Question 5 Comments:			
		primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~	primary control center functionality and which have a Medium VRF.	primary control center functionality and which have a High VRF.	
R5 VSL					
R5		The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.

Organization	Question 5:	Question 5 Comments:			
		primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	primary control center functionality and which have a Medium VRF.	primary control center functionality and which have a High VRF.	
R6: The SDT agrees and has made changes accordingly. The VSL content for Requirement R6 was changed in response to other comments received however. **R6 VSL**					
R6		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, ~~with evidence of its last issue,~~ was reviewed and approved but it was not done in one calendar year ~~more than twelve calendar months and less than or equal to fifteen calendar months~~ or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes ~~to the backup~~	~~The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in more than two calendar years fifteen calendar months or that it was updated more than ninety calendar days after any changes to the backup location, capabilities, or contact information.~~ N/A	~~N/A~~ The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in two calendar years or more or that it was updated more than ninety calendar days after any changes to the capabilities described in Requirement R1.	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator, does not have evidence that it's dated, current, in force Operating Plan for backup functionality was reviewed and approved.

Organization	Question 5:	Question 5 Comments:
		~~location,~~ capabilities described in Requirement R1~~, or contact information~~.
Southern Company Transmission	No	**For Requirement 5, a cursory review of the applicable BA and TOP standards left uncertainty as to whether some standards pertain to monitoring, control, logging, or alarming actions within the requirements. For example, BAL-005 states that the TOP must be included with the metered boundaries of a BA Area. NERC standard COM-001 states the TOP shall provide adequate and reliable telecommunications facilities. Unless there is a definite and an agreeable number of standards applicable to the TOP and BA pertaining to monitoring, control, etc., it is difficult to determine whether you exceed the 70/80/90% thresholds associated with Lower, Moderate, or High VSLs. Until there is a predetermined number of applicable standards that can be used as a benchmark for determining the correct level of VSL, it is recommended that only the Severe VSL be utilized along with its current criteria.** For R8, it is recommended that the 3 components contained within the Lower VSL be staged for Lower, Moderate, and High VSL. For example, if an registered entity failed to fulfill one of the components (e.g., testing for less than 2 hours), this would result in a Lower VSL. If a registered entity failed two components (e.g., tested < 2 hours AND it was done in more than 12 calendar months), then this would equate to a Moderate VSL. To fail to meet all three components would equate to a High VSL.

Response: R5: The SDT agrees and has modified the VSL for R5 to not rely upon a determination of the applicable percentages.

R5 VSL

R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with

Organization	Question 5:	Question 5 Comments:				
		~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	~~r~~Requirement R5.	

R8: The SDT agrees and has modified the VSL for R8 accordingly.

R8 VSL

R8		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.

Organization	Question 5:	Question 5 Comments:				
		backup functionality, but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.	less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented. ~~N/A~~	for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented. ~~N/A~~		
Duke Energy	No	Once the requirements are revised, the VSLs need to be revisited and cleaned up accordingly. For example, the Lower, Medium and High VSLs for R4 and R5 are unworkable - how can anyone document that the backup functionality includes monitoring, control, logging and alarming sufficient to maintain compliance with 90%,80%, 70% of the applicable requirements of other standards? This would require an impossible burden of recordkeeping. The VSL for R8 imposes a new requirement - that the entity demonstrate through a test that the transition time is less than or equal to two hours.				

Organization	Question 5:	Question 5 Comments:

Response: R4 and R5: The SDT agrees and has modified the VSLs for Requirements R4 and R5 to not rely upon percentages.

R4 VSL

R4	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.

Organization	Question 5:	Question 5 Comments:		
R5 VSL				
R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.

Organization	Question 5:	Question 5 Comments:

R8: Requirement R1.5 clearly indicates a transition time that is not to exceed 2 hours so demonstrating this in the annual test is not a new requirement. However, to avoid confusion, the SDT has altered the wording of Requirement R1.5. The SDT has also modified the High VSL for Requirement R1 to address the importance of this transition time.

R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours.

R1 VSL

R1	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing one of the sub-requirements or the plan ~~is~~ does not ~~dated with evidence~~reflect the date of its last ~~issue~~issuance.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing two of the sub-requirements	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing three or more of the sub-requirements or is not compliant with Requirement R1.5.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator does not have a~~n~~ current Operating Plan for backup functionality.

Organization	Question 5:	Question 5 Comments:
MRO NERC Standards Review Subcommittee	No	R1, part of the Lower VSL category of non compliance is "…not dated with evidence of its last issue date.", this is not contained within any part of R1. The VSL Criteria Straw man Document sites that for procedures/programs, in the Lower Category, "The responsible entity has demonstrated the existence of required procedure/program but is missing minor details or minor program/procedural elements. Such deficiencies would not impact the achievement of the objective of the requirement." Recommend that "?not dated with evidence of its last issue date." be deleted from R1's VSL. R4, part of the Lower VSL category of non compliance is "?or the evidence of its demonstration is not dated.", this is not contained within any part of R4. The VSL Criteria Straw man Document sites that for procedures/programs, in the Lower Category, "The responsible entity has demonstrated the existence of required procedure/program but is missing minor details or minor program/procedural elements. Such deficiencies would not impact the achievement of the objective of the requirement." Recommend that "?or the evidence of its demonstration is not dated" be deleted from R4's VSL.

Organization	Question 5:	Question 5 Comments:
		R5, part of the Lower VSL category of non compliance is "?or its evidence is not dated.", this is not contained within any part of R5. The VSL Criteria Straw man Document sites that for procedures/programs, in the Lower Category, "The responsible entity has demonstrated the existence of required procedure/program but is missing minor details or minor program/procedural elements. Such deficiencies would not impact the achievement of the objective of the requirement." Recommend that "…or its evidence is not dated" be deleted from R5's VSL. R7, part of the Severe VSL category of non compliance states "?dated evidence shows that?", the word "dated" is not contained within any part of R7. R8, part of the Lower VSL category of non compliance is "?has provided evidence, such as dated records, that it has tested its dated, current, in force Operating Plan for backup functionally, with evidence of its last issue, through actual implementation?" If an Entity accomplished this they would BE compliant. Perhaps the SDT forgot to add a deficiency (negative aspect) to a minor detail within the VSL. Overall it seems that the SDT has been directed to place some sort of "date (d)" qualifier within the VSLs. If there is another document that is directing this (i.e., Generally Accepted Government Accounting Standards?), it would be helpful to the Utility Industry of what that document is. VSLs should be a direct reflection of the Requirements.

Response: R1 – The SDT has modified the requirement to add a timing factor. This is now also reflected in the VSL.

R1 Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a~~n~~ current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This Operating Plan for backup functionality shall include the following at a minimum:

R1 VSL

R1	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing one of the sub-requirements or the plan ~~is~~ does not ~~dated~~	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing two of the sub-requirements.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing three or more of the sub-requirements or is not compliant with	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator does not have a~~n~~ current Operating Plan for backup functionality.

Organization	Question 5:	Question 5 Comments:		
	~~with evidence~~reflect the date of its last ~~issue~~issuance.		Requirement R1.5.	

R7 – "Dated' has been deleted from the VSL.

R7 VSL

R7	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator's ~~dated~~ evidence does not demonstrate~~shows~~ that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for the functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality.

R4, R5, R8 - The word "dated" was removed from the Lower VSLs for both Requirement R4 and Requirement R5 and from the Lower and Severe VSLs for Requirement R8 as suggested.

R4	The Reliability Coordinator has demonstrated that it has a backup control	The Reliability Coordinator has demonstrated that it has a backup control	The Reliability Coordinator has demonstrated that it has a backup control	The Reliability Coordinator has not demonstrated that it has a backup control

Organization	Question 5:	Question 5 Comments:		
	center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~.	center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.
R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center

Organization	Question 5:	Question 5 Comments:			
		facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	facility or contracted services) in accordance with ~~r~~Requirement R5.
R8		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality,	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was for less than two	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.

		but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.	continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented.~~N/A~~	continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented. ~~N/A~~	

Organization	Question 5:	Question 5 Comments:
ITC	No	The VSLs for Requirement 3 don't make any sense. Per comments elsewhere, this requirement should be re-written to focus on delegated functions. It is unlikely multiple entities would be involved as implied in the VSLs. For requirement 4 and 5, the VSL would be nearly impossible to calculate or measure from a practical standpoint. The VSL should not be focused on the number of other Standards that would be violated, but on the Plan itself or the functions. For requirement 7, the only VSL (severe) does not make any sense, further evidence that the requirement itself is not appropriate, as commented elsewhere. For requirement 8, the drafting team should develop VSLs for all levels, similar to requirement 1.

Organization	Question 5:	Question 5 Comments:

Response: R3: The SDT agrees and has modified the VSL for Requirement R3. The SDT does believe that multiple entities may well be involved, but determined to define the VSL against other factors than the percentage of entities that were not provided for.

R3 VSL

R3	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Lower VRF ~~for 10% or less of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Medium VRF ~~for more than 10% and less than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a High VRF~~for more than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of any such entity's control functionality in its Operating Plan for backup functionality.

R4 and R5: The SDT agrees and has modified the VSL for Requirements R4 and R5 to not rely on percentages.

R4 VSL

R4	The Reliability Coordinator has demonstrated that it	The Reliability Coordinator has demonstrated that it	The Reliability Coordinator has demonstrated that it	The Reliability Coordinator has not demonstrated that it

Organization	Question 5:	Question 5 Comments:		
	has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~	has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.
R5 VSL				
R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup

Organization	Question 5:	Question 5 Comments:

functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.

R7: As noted previously, the SDT believes that Requirement R7 is needed. The SDT believes that Requirement R7 is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT and the VSL has been clarified as well.

R7. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.

R7 VSL

Organization	Question 5:	Question 5 Comments:			
R7		N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator's ~~dated~~ evidence does not demonstrate~~shows~~ that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for the functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality.
R8: The SDT agrees and has defined all four VSL categories for Requirement R8. **R8 VSL**					
R8		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality,	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was for less than two	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.

Organization	Question 5:	Question 5 Comments:

	but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.	continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented. ~~N/A~~	continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented. ~~N/A~~	

Organization	Question 5:	Question 5 Comments:
Western Area Power Administration	No	Suggestion is to apply percentage levels to requirements as opposed to percentage levels to standards (as this is currently written).

Response: R4 and R5: The SDT has modified the VSL to not rely on percentages.

R4 VSL

R4	The Reliability Coordinator has	The Reliability Coordinator has	The Reliability Coordinator has	The Reliability Coordinator has not

Organization	Question 5:	Question 5 Comments:		
	demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~.	demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.
R5 VSL				
R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated

Organization	Question 5:	Question 5 Comments:			
		it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~,~~ ~~or its evidence is not dated.~~	it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.
Pepco Holdings, Inc. - Affiliates	No	R2 - need to recognize there may be more than one backup facility — wording implies one primary facility and one backup facility. R3 has increments on number of entities rather than number of BES facilities. Concentrating on entities does not address the real issue. R4 and R5 concentrate on percentage of standards met by relying on backup facility rather than number of facilities still under monitoring and control.			

Organization	Question 5:	Question 5 Comments:

Response: R2: The SDT agrees and has modified the wording of the VSL for Requirement R2 to not rely on an assumption that there are only two facilities involved.

R2 VSL

R2		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality ~~but the plan is not located~~ available ~~in~~ at ~~one~~all of its control locations but at one location it is not the current plan.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality ~~but the plan is not located~~ available ~~in~~at ~~either~~ all of its control locations but at all locations it is not the current plan.	N/A	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality but no version of the plan is available at all of its control locations.

R3: The SDT agrees and has modified the VSL to define levels against other factors than the percentage of entities that were not provided for.

R3 VSL

R3		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of any such entity's control functionality in its Operating Plan for

Organization	Question 5:	Question 5 Comments:			
		one or more Requirements in the Reliability Standards having a Lower VRF ~~for 10% or less of its applicable entities~~ in its Operating Plan for backup functionality.	one or more Requirements in the Reliability Standards having a Medium VRF ~~for more than 10% and less than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	one or more Requirements in the Reliability Standards having a High VRF~~for more than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	backup functionality.
R4 and R5: The SDT agrees and has modified the VSL for R4 and R5 to not rely on percentages. **R4 VSL**					
R4		The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.

Organization	Question 5:	Question 5 Comments:		
	applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~.	applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	
R5 VSL				
R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.

Organization	Question 5:	Question 5 Comments:

		and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	

Organization	Question 5:	Question 5 Comments:
PJM Interconnection	No	Changes need to be made to address the primary/backup language (see 7 below)
Response: Please see our response to question 7 comments.		
Ameren	No	Guideline 3 of FERC's order conditionally approving VSLs for the original 83 regulatory approved standards stipulates that the VSL should not add to the requirement. The Lower VSL of R1 does add a requirement for the document to be dated which violates Guideline 3. Requirement 1 fits the multi-component category of the VSL Guidelines. This category puts the number of sub-requirements that are missing from the Operating Plan into quartiles. Thus, the Lower VSL would be missing one or two sub-requirements the Moderate VSL would be missing three or four sub-requirements the High VSL would be missing five to six sub-requirements and the Severe VSL would be missing seven sub-requirements or the plan would not exist. The VSLs for Requirement 2 should use the term back-up capability along with primary control center for consistency with the requirements. We agree with these levels. The VSLs for Requirement 3 really don't make any sense. It implies there may be more than one other entity that a TOP is directing BES operations through. We don't think that this is likely. Additionally, the VSLs as written do not seem to fit any category within the VSL guidelines document. Why would the VSLs not be divided into quartiles? For the requirement 4, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities foreseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the BA or TOP has a backup capability plan, isn't the BA or TOP still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double

Organization	Question 5:	Question 5 Comments:
		jeopardy? For the requirement 5, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities foreseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the RC has a backup control center, isn't the RC still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? Perhaps the drafting team should consider applying VSLs based on if monitoring, control, logging and alarming are included in the backup capability. In its order approving VSLs, the FERC stated in paragraph 27 that they prefer gradated VSLs whenever possible. For requirement 6, we believe a VSL could be written for each severity level using the time requirements established. For instance, high could apply to 18 months and severe to 21 months. Additionally, the VSLs for requirement 6 violation FERC's guideline 3 by requiring the Operating Plan to be dated. The associated requirement does not mention dating. For requirement 7, the only VSL does not make any sense. The VSL implies that the responsible entity may provide evidence that backup plan depends on the primary control center. Why would the responsible entity providing evidence of non-compliance be a severity level? The purpose of providing evidence is to demonstrate compliance. Is this requirement 7 even needed? There are requirements in this standard that require a backup plan. The responsible entity is responsible to comply with this standard and with all other standards even when operating with the backup plan. Can they comply with other standards if the backup plan depends on the primary control center and the primary control center is destroyed? No. Thus, they would violate many other standards. Thus, requirement 7 is implied and not needed explicitly as a requirement. For requirement 8, we do not support a mandatory testing time of two hours or a transition time of two hours. However, considering the requirement as written, we suggest the drafting team could develop VSLs for all levels. VSLs could be written as: Lower: Tested the back plan for less than 30 minutes or The transition time was more than two hours but less than or equal to 3 hours or the test results and lessons learned were not incorporated in subsequent revisions. Moderate: Tested the backup plan for 30 minutes or more but less than one hour. The transition time was more than three hours but less than or equal to four hours. High: Tested the back plan for one hour or more but less than 90 minutes or The transition time was more than four hours but less than or equal to five hours. Severe: Tested the back plan for 90 minutes or more but less than two hours or The transition time was more than five hours. For requirement 9, the VSL perpetuates some of the problems that are currently occurring with compliance monitoring of

Organization	Question 5:	Question 5 Comments:
		requirements that have periodic reporting requirements to the Regional Entity. The Regional Entity either already has the evidence or a violation has occurred because the report was not submitted on time. The responsible entity should not have to redemonstrate to the compliance auditor that it submitted the plan to the Regional Entity since the compliance auditor is the Regional Entity.
ISO/RTO Council	No	Guideline 3 of FERC's order conditionally approving VSLs for the original 83 regulatory approved standards stipulates that the VSL should not add to the requirement. The Lower VSL of R1 does add a requirement for the document to be dated which violates Guideline 3. Requirement 1 fits the multi-component category of the VSL Guidelines. This category puts the number of sub-requirements that are missing from the Operating Plan into quartiles. Thus, the Lower VSL would be missing one or two sub-requirements the Moderate VSL would be missing three or four sub-requirements. the High VSL would be missing five to six sub-requirements and the Severe VSL would be missing seven sub-requirements or the plan would not exist. The VSLs for Requirement 2 should use the term back-up capability along with primary control center for consistency with the requirements. R2 requires a copy of the plan be provided at both the primary and backup facilities. Failing to provide any copy at all is a complete violation of the requirement and hence should be assigned a Severe VSL, not Medium (note that VSL is a measure of the extent to which a requirement is not met, not its impact). We therefore suggest to move the two conditions from Low/Medium to High/Severe in accordance with established VSL guideline. The VSLs for Requirement 3 really don't make any sense. It implies there may be more than one other entity that a TOP is directing BES operations through. We don't think that this is likely. Additionally, the VSLs as written do not seem to fit any category within the VSL guidelines document. Why would the VSLs not be divided into quartiles based the number of entities? For the requirement 4, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities foreseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the BA or TOP has a backup capability plan, isn't the BA or TOP still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? The Severe level should include a condition that the RC provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards.

Organization	Question 5:	Question 5 Comments:
		For the requirement 5, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities foreseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the RC has a backup control center, isn't the RC still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? Perhaps the drafting team should consider applying VSLs based on if monitoring, control, logging and alarming are included in the backup capability. The Severe level should include a condition that the BA or TOP provides less than 70% of the functionality required for maintaining compliance with the Reliability Standards applicable to an RC. Otherwise, there will not be any VSL for RC providing functionality sufficient for maintaining compliance with, say, 40% of the Reliability Standards. Further, the proposed wording change, i.e., <70%, covers the condition of not having any functionality at all to comply with reliability standards. In its order approving VSLs, the FERC stated in paragraph 27 that they prefer gradated VSLs whenever possible. For requirement 6, we believe a VSL could be written for each severity level using the time requirements established. For instance, high could apply to 18 months and severe to 21 months. Additionally, the VSLs for requirement 6 violate FERC's guideline 3 by requiring the Operating Plan to be dated. The associated requirement does not mention dating. There are no VSLs assigned to High and Severe. We suggest the SDT to provide the conditions that an entity fails to meet the bulk of the intent of this requirement (High) and fails to meet this requirement completely (Severe). For example, a High VSL can be assigned if the entity did not update its plan after 18 months or 120 calendar days after changes were made to the backup capability; a Severe for failing to update its plan for a longer time period or at all. For requirement 7, the only VSL does not make any sense. The VSL implies that the responsible entity may provide evidence that backup plan depends on the primary control center. Why would the responsible entity providing evidence of non-compliance be a severity level? The purpose of providing evidence is to demonstrate compliance. Is this requirement 7 even needed? There are requirements in this standard that require a backup plan. The responsible entity is responsible to comply with this standard and with all other standards even when operating with the backup plan. Can they comply with other standards if the backup plan depends on the primary control center and the primary control center is destroyed? No. Thus, they would violate many other standards. Thus, requirement 7 is implied and not needed explicitly as a requirement. For requirement 8, we do not support a mandatory testing time of two hours or a transition time of two hours. However, considering the requirement as written, we suggest the drafting team could develop VSLs for all levels. VSLs could be written as: Lower: Tested the back plan for 90 minutes or more but less than two hours or The transition time was more than two hours but less than or equal to 3 hours. Moderate: Tested the back plan for one hour or more but less than 90 minutes. The transition time was more than three

Organization	Question 5:	Question 5 Comments:
		hours but less than or equal to four hours. High: Tested the backup plan for 30 minutes or more but less than one hour or The transition time was more than four hours but less than or equal to five hours. Severe: Tested the back up plan for less than 30 minutes or The transition time was more than five hours or or the test results and lessons learned were not incorporated in subsequent revisions. For requirement 9, the VSL perpetuates some of the problems that are currently occurring with compliance monitoring of requirements that have periodic reporting requirements to the Regional Entity. The Regional Entity either already has the evidence or a violation has occurred because the report was not submitted on time. The responsible entity should not have to redemonstrate to the compliance auditor that it submitted the plan to the Regional Entity since the compliance auditor is the Regional Entity.
Midwest ISO	No	Guideline 3 of FERC's order conditionally approving VSLs for the original 83 regulatory approved standards stipulates that the VSL should not add to the requirement. The Lower VSL of R1 does add a requirement for the document to be dated which violates Guideline 3. Requirement 1 fits the multi-component category of the VSL Guidelines. This category puts the number of sub-requirements that are missing from the Operating Plan into quartiles. Thus, the Lower VSL would be missing one or two sub-requirements the Moderate VSL would be missing three or four sub-requirements the High VSL would be missing five to six sub-requirements and the Severe VSL would be missing seven sub-requirements or the plan would not exist. The VSLs for Requirement 2 should use the term back-up capability along with primary control center for consistency with the requirements. We agree with these levels. The VSLs for Requirement 3 really don't make any sense. It implies there may be more than one other entity that a TOP is directing BES operations through. We don't think that this is likely. Additionally, the VSLs as written do not seem to fit any category within the VSL guidelines document. Why would the VSLs not be divided into quartiles? For the requirement 4, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities foreseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the BA or TOP has a backup capability plan, isn't the BA or TOP still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy?

Organization	Question 5:	Question 5 Comments:
		For the requirement 5, the Lower VSL violates FERC's guideline 3 established in their order conditionally approving VSLs since the VSL indicates a date which is not in the requirement. Additionally, the VSLs do not consider most of the range of possibilities foreseen by the drafting team. For example, compliance with 83% of the reliability standards does not fit any VSL. Review of these VSLs cause us to question if the associated requirement needs to be modified. If the requirement is that the RC has a backup control center, isn't the RC still required to comply with all other reliability standards? Thus, why does the requirement need to explicitly state this. Doesn't this present an opportunity for double jeopardy? Perhaps the drafting team should consider applying VSLs based on if monitoring, control, logging and alarming are included in the backup capability. In its order approving VSLs, the FERC stated in paragraph 27 that they prefer gradated VSLs whenever possible. For requirement 6, we believe a VSL could be written for each severity level using the time requirements established. For instance, high could apply to 18 months and severe to 21 months. Additionally, the VSLs for requirement 6 violation FERC's guideline 3 by requiring the Operating Plan to be dated. The associated requirement does not mention dating. For requirement 7, the only VSL does not make any sense. The VSL implies that the responsible entity may provide evidence that backup plan depends on the primary control center. Why would the responsible entity providing evidence of non-compliance be a severity level? The purpose of providing evidence is to demonstrate compliance. Is this requirement 7 even needed? There are requirements in this standard that require a backup plan. The responsible entity is responsible to comply with this standard and with all other standards even when operating with the backup plan. Can they comply with other standards if the backup plan depends on the primary control center and the primary control center is destroyed? No. Thus, they would violate many other standards. Thus, requirement 7 is implied and not needed explicitly as a requirement. For requirement 8, we do not support a mandatory testing time of two hours or a transition time of two hours. However, considering the requirement as written, we suggest the drafting team could develop VSLs for all levels. VSLs could be written as: Lower: Tested the back plan for 90 minutes or more but less than two hours or The transition time was more than two hours but less than or equal to 3 hours or the test results and lessons learned were not incorporated in subsequent revisions. Moderate: Tested the back plan for one hour or more but less than 90 minutes The transition time was more than three hours but less than or equal to four hours. High: Tested the backup plan for 30 minutes or more but less than one hour or The transition time was more than four hours but less than or equal to five hours. Severe: Tested the back plan for less than 30 minutes or The transition time was more than five hours. For requirement 9, the VSL perpetuates some of the problems that are currently occurring with compliance monitoring of requirements that have periodic reporting requirements to the Regional Entity. The Regional Entity either already has the evidence or a violation has occurred because the report was not submitted on time. The responsible entity should not have

Organization	Question 5:	Question 5 Comments:
		to redemonstrate to the compliance auditor that it submitted the plan to the Regional Entity since the compliance auditor is the Regional Entity.

Response: R1 – The SDT has modified the requirement to add a timing factor.

R2: While the terminology used was not identical it is technically correct and no change was made.

R3: The SDT agrees and has modified the VSL for Requirement R3. The SDT does believe that multiple entities may well be involved, but determined to define the VSL against other factors than the percentage of entities that were not provided for.

R3 VSL

R3		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Lower VRF ~~for 10% or less of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Medium VRF ~~for more than 10% and less than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a High VRF~~for more than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of any such entity's control functionality in its Operating Plan for backup functionality.

R4/R5: The SDT has modified the VSL for R4 and R5. The word, "dated" was removed from the Lower VSL for R4.

Organization	Question 5:	Question 5 Comments:

Simply having a backup control center does not automatically imply that it will adhere to relevant standards, therefore the need for the phrase. Double jeopardy shouldn't be an issue as this requirement applies only to the backup.

R4 VSL

R4	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.

Organization	Question 5:	Question 5 Comments:		
R5 VSL				
R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.

Organization	Question 5:	Question 5 Comments:

R6: The requirement includes the phrase, “annually review and approve” and the only way to see if the plan has been reviewed and approved on an annual basis is to look at the dates of the documents over several years. No change made.

R7: The SDT agrees and has modified the VSL for Requirement R7 to be based on an inability to show compliance rather than a showing of non-compliance. The SDT does believe Requirement R7 is an appropriate and needed requirement. While it may appear implied to some, the SDT believes it is too important an issue to be left to implication.

R7 VSL

R7	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator’s ~~dated~~ evidence does not demonstrate~~shows~~ that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for the functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality.

R8: The SDT believes that a two-hour continuous test is appropriate in that it ensures that the functionality is tested through at least one full clock hour. The SDT did modify the VSL for Requirement R8 to reflect increasing levels of severity of non-compliance.

R8 VSL

R8	The Reliability	The Reliability	The Reliability	The Reliability

Organization	Question 5:	Question 5 Comments:			
		Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality, but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.	Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented. ~~N/A~~	Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented. ~~N/A~~	Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.

Organization	Question 5:	Question 5 Comments:
R9: The SDT sees this as a necessary part of the documentation required and not a burdensome requirement so no change has been made.		
FirstEnergy Corp.	No	The VSLs for Requirement 3 implies this method of operation is employed only when a TOP is directing operations through more than one other entity. We don't believe this to be the norm. The drafting team should consider the failure to include provisions for the loss of a percentage of such entity's or entities' total control functionality rather than basing the compliance measurement on the percentage of entities. For the requirement 4, the VSL's should be revised based on the needed revisions to the associated requirement. For the requirement 5, the VSL's should be revised based on the needed revisions to the associated requirement. For requirement 6, we believe a VSL could be written for each severity level using the time requirements established. For instance, high could apply to 18 months and severe to 21 months. For requirement 7, the VSL's should be revised based on the needed revisions to the associated requirement. For requirement 8, there is nothing in Requirement 8 as currently proposed by the drafting team that requires a two hour test. If there is an expectation for a test of the backup center to last two hours, it should be stated in the requirement. The VSL for Requirement 8 should be rewritten based on the needed revisions to the associated requirement. For requirement 9, the Regional Entity either already has the evidence or a violation has occurred because the report was not submitted on time. The responsible entity should not have to redemonstrate to the compliance auditor that it submitted the plan to the Regional Entity since the compliance auditor is the Regional Entity.

Response: R3: The SDT agrees and has modified the VSL for Requirement R3. The SDT does believe that multiple entities may well be involved, but determined to define the VSL against other factors than the percentage of entities that were not provided for.

R3 VSL

R3		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against

Organization	Question 5:	Question 5 Comments:			
		~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Lower VRF ~~for 10% or less of its applicable entities~~ in its Operating Plan for backup functionality.	~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Medium VRF ~~for more than 10% and less than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a High VRF~~for more than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	~~included provisions for~~ the loss of any such entity's control functionality in its Operating Plan for backup functionality.
R4/R5: The SDT agrees and has modified the VSL for Requirements R4 and R5 accordingly. **R4 VSL**					
R4		The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.

Organization	Question 5:	Question 5 Comments:			
		for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~	for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	
R5 VSL					
R5		The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.

Organization	Question 5:	Question 5 Comments:			
		~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF	

R6: VSL for Requirement R6 was changed due to several comments.

R6 VSL

R6		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, ~~with evidence of its last issue,~~ was reviewed and approved but it was not done in one calendar year ~~more than twelve calendar months and less than or equal to fifteen~~	~~The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in more than two calendar years fifteen calendar months or that it was updated more than~~	~~N/A~~ The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in two calendar years or more or that it was updated more than ninety calendar days after any	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator, does not have evidence that it's dated, current, in force Operating Plan for backup functionality was reviewed and approved.

Organization	Question 5:	Question 5 Comments:			
		~~calendar months~~ or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes ~~to the backup location,~~ capabilities described in Requirement R1~~, or contact information~~	~~ninety calendar days after any changes to the backup location, capabilities, or contact information.~~ N/A	changes to the capabilities described in Requirement R1.	

R8. Requirement R8.2 does require a minimum of two continuous hours so no changes were made. However, the VSL for Requirement R8 was changed in response to other comments.

R8 VSL

R8		The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality, but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.

Organization	Question 5:	Question 5 Comments:

		two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.	documented.~~in~~ ~~N/A~~	documented. ~~N/A~~	

R9. The SDT sees this as a necessary part of the documentation required and not a burdensome requirement so no change has been made.

Organization	Question 5:	Question 5 Comments:
WECC Reliability Coordinator Comment Working Group	Yes	
ComEd / Exelon	Yes	
Manitoba Hydro	Yes	
Entergy	Yes	

Organization	Question 5:	Question 5 Comments:
Services, Inc		
Electric Reliability Council of Texas, Inc.	Yes	
Oncor Electric Delivery	Yes	
Santee Cooper	Yes	
ReliabilityFirst Corporation	Yes	
Bonneville Power Administration	Yes	
AEP	Yes	
Bureau of Reclamation	Yes	
Northeast Utilities	Yes	
Response: Thank you for your response.		

6. The SDT has provided an Implementation Plan with this posting. Do you agree with the implementation timeframe that shows all requirements going into effect on the same time/date? If not, please provide specific suggestions for improvement.

Summary Consideration:

The vast majority of the comments received were supportive of the Implementation Plan. There were only a very few comments that expressed concern about the ability to get backup capability fully functioning within 24 months of adoption of the standard. The SDT understands the importance of backup control capability to reliability and recognizes the balance between doing this rapidly and the practical realities of being able to accomplish it and the relative priority of other standards compliance activities. The SDT considered these questions and agrees with the majority of commenters that 24 months is the correct timeframe. Therefore, no changes have been made.

However, to provide clarity, the following requirements have been changed:

R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours.

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

Organization	Question 6:	Question 6 Comments:
Puget Sound Energy	No	This depends on the interpretation of R.5. The statement of "during the time period when the primary control center and the back up functionality are both available for use" is vague. Does this refer to the time period when an entity is in the process of constructing a backup facility or is it referring to the transition time in R.1.5? If it is the time of R.1.5, this is a huge monetary and resource burden. Essentially it would require an entity to have a staffed fully redundant backup facility 24x7, or a contract with another entity with 24x7 staff properly trained to monitor, control, log and respond to alarms on another

Organization	Question 6:	Question 6 Comments:
		entities entire system. If this is the case, then 24 months may not be adequate.
Response: The SDT agrees with the majority of commenters that 24 months is the correct timeframe for this standard. However, R1.5 and R5 were clarified to avoid confusion as to what is required and R5.1 & R5.2 have been added for additional clarity. It is intended that a backup to the backup is clearly not required. For example, it is intended to ensure that while you were operating out of your backup during loss of the primary control center that the requirement should not be interpreted to require an additional backup. This taken in concert with Requirement 1.5 contemplates that the backup can be activated and fully operational within 2 hours. It is the SDT opinion that this standard does not require a full-time fully-staffed backup capability. It is believed that off-duty trained operators can be called out in a manner to arrive at the backup capability within 2 hours, and that the control system used by the backup capability could either be always hot or able to be remotely started during the period that operators are en route. **R1.5** A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours. **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less. **R5.2** Unplanned outages of the primary or backup functionality.		
Entergy System Planning & Operations (Generation & Marketing)	No	Consider adding to the implementation requirement that entities comply within the timeframe stated or if an entity believes it will take longer than the specified time to become compliant, allowing entities to apply for an extension to the timeframe stated if that entity can justify the need for an extension to its Regional Compliance Entity. Each entity desiring the extension shall submit a plan and obtain approval from its Regional Compliance Entity within 6 months of approval of this standard. The Regional Compliance entity will review the requests and approve on a case by case basis. Compliance would be required after the date approved by the Regional Compliance Entity.
Response: Procedures exist for an entity that has challenges complying with standards to work with the Regional Compliance Entity on mitigation plans. The SDT does not believe it would be appropriate to embed such concepts into standards**.**		
Progress	No	Effective Date — 24 months is not adequate time to address such a significant change in requirements from EOP-008-0.

Organization	Question 6:	Question 6 Comments:
Energy Carolinas, Inc.		The requirement is changing from a recovery plan to a hot-standby backup available within 2 hours. Additional time is needed to choose a backup methodology, budget accordingly, purchase/construct a backup site (or negotiate with another entity, though the feasibility of this is questionable), design backup voice and data communications, and implement — all per CIP requirements while upgrading existing primary equipment/facilities to meet CIP requirements with implementation schedules through 2010. This requires multi-million dollar actions that must be addressed with a methodologically sound approach to avoid rework and undue financial burden. PEC suggests an implementation period of 1) 36 months for Substantial Progress (i.e. groundbreaking) and 2) 48 months for full implementation.
Progress Energy-Florida	No	Effective Date — 24 months is not adequate time to address such a significant change in requirements from EOP-008-0. The requirement is changing from a recovery plan to a hot-standby backup available within 2 hours. Additional time is needed to choose a backup methodology, budget accordingly, purchase/construct a backup site (or negotiate with another entity, though the feasibility of this is questionable), design backup voice and data communications, and implement —all per CIP requirements while upgrading existing primary equipment/facilities to meet CIP requirements with implementation schedules through 2010. This requires multi-million dollar actions that must be addressed with a methodologically sound approach to avoid rework and undue financial burden. PEF suggests an implementation period of 1) 36 months for Substantial Progress (i.e. groundbreaking) and 2) 48 months for full implementation.
Response: The SDT agrees with the majority of commenters that 24 months is the correct timeframe for this standard. Therefore, no changes have been made.		
NPCC	Yes	
Southern Company Transmission	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
Electric Reliability Council of	Yes	

Organization	Question 6:	Question 6 Comments:
Texas, Inc.		
MRO NERC Standards Review Subcommittee	Yes	
ITC	Yes	
Oncor Electric Delivery	Yes	
Western Area Power Administration	Yes	
ISO New England Inc	Yes	
Independent Electricity System Operator	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Santee Cooper	Yes	
ReliabilityFirst Corporation	Yes	

Organization	Question 6:	Question 6 Comments:
Bonneville Power Administration	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
Dynegy	Yes	
Hydro-Québec TransÉnergie (HQT)	Yes	
PJM Interconnection	Yes	
AEP	Yes	
Ameren	Yes	
FirstEnergy Corp.	Yes	
Bureau of Reclamation	Yes	
ISO/RTO Council	Yes	

Organization	Question 6:	Question 6 Comments:
Northeast Utilities	Yes	
Midwest ISO	Yes	
WECC Reliability Coordinator Comment Working Group	Yes	
San Diego Gas and Electric	Yes	
ComEd / Exelon	Yes	
Manitoba Hydro	Yes	
Response: Thank you for your response.		

7. Are there any other issues that need to be addressed? Please be specific.

Summary Consideration:

There were a number of comments raised that presented the SDT with an opportunity to provide additional clarity to a number of items. Therefore, the following requirements have been changed due to industry comments to this question:

R1.2 An ~~overview~~ summary description of the elements required to support the backup functionality.

R1.5 A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours.

R1.6 An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time ~~to~~ to fully implement the backup functionality elements identified in Requirement R1.2~~get backup functionality up and running~~. The Operating Process shall also include:

R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary~~/~~ or backup functionality.

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

R6.1 ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~.

R7. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.

M1. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format. ~~, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable~~.

Organization	Question 7:	Question 7 Comments:
Consumers Energy Company	Yes	This standard is overbearing and requires far more documentation than is needed to maintain reliability and accomplish the goals of adequate back-up facilities. For example, could the annual test be considered the review of the Operating Plan? Is it sufficient documentation that proof a test has been conducted and was successful in operating the system?
Response: The SDT is following the FERC directives as outlined in Orders 693 and 693A. The SDT feels that testing of the Operating Plan is required and that R8 clearly describes the testing needed to satisfy the standard.		
Puget Sound Energy	Yes	R.5 needs further clarification as stated in my response to the previous question.R.1.6.2. The definition of "actions to manage risk" is vague. This again points to R.5. If an entity has notified affected entities that it is in the process of transitioning to the back up facility and made notifications to implement the plan, aren't these actions to manage risk to the BES? I am not sure what the SDT had in mind with this requirement.
Response: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified R5 to provide clarity on this matter. **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:		

Organization	Question 7:	Question 7 Comments:
R5.1 Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality		
San Diego Gas and Electric	Yes	R5 - We would like to get some clarification on Requirement 5, particularly with respect to the opening sentence that refers to the time period when primary and backup control center functionality is available for use, then the requirement is to have backup functionality. If both primary and backup control centers are available for use, doesn't that automatically mean that backup functionality is available? Please clarify the meaning of this Requirement. R6.1 - We would like further clarification to the term "changes to the backup capabilities" that would require an update and approval of the Operating Plan. What are examples of changes to backup capabilities that would trigger an update of the Operating Plan? What are examples of changes to backup capabilities that are considered more "minor" that wouldn't require an update?
Response: R5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirement R5 to provide clarity on this matter. **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality R6.1: The SDT clarified Requirement R6.1. **R6.1** ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~.		
ComEd / Exelon	Yes	R5 addresses maintaining the backup functionality that includes monitoring, control, logging, and alarming. M5 requires dated evidence (documentation) that you have demonstrated the backup functionality for the requirements in R5. However R8.2 addresses the testing of the backup functionality through actual implementation or test operation for a minimum of two consecutive hours. The requirements of R5 should be incorporated into R8.2 and therefore R5 eliminated as a standalone

Organization	Question 7:	Question 7 Comments:
		requirement. As it is currently written in draft 2, R5 & R8.2 are redundant and M5 & M8 are redundant in terms of practical application and verification of compliance.
Response: The SDT does not feel a need to integrate Requirement R5 with Requirement R8 because they are not redundant. Requirement R5 deals with required functionality and R8 deals with testing that functionality. They are two separate requirements.		
Entergy System Planning & Operations (Generation & Marketing)	Yes	The use of the term "control center" needs definition and align with that which will be used in the CIP critical asset identification methodology. The terms "primary" and "back up" control center or functionality should also be defined. R1.1 the use of the term "prolonged" is subjective and should be revised to identify a definite period of time. R1.2.4 the actual power supply requirements should go here. BAL-005 R15 regarding back up power supplies should be revised and transplanted to this standard. consider consulting with the BACSDT on moving and enhancing this requirement. R1.3 is vague - "Keeping consistent" may be redundant to the requirements already listed unless it is intended to mean something else. if so, be specific. R4 & 5 both contain the phrase "during the time when the primary control center functionality and the backup functionality are both available for use". what is the intent of this phrase. Does this mean that the remainder of the requirement does not apply if both are not available for use? Recommend removing this phrase from both requirements. R6.1 should apply only to changes that are related to Reliability Standards or other items specifically identified. Otherwise even very minor changes (such as corporate related features) would be subject to this requirement even though there is no reliability impact. R8. the term "annual" needs better definition in this standard or within the NREC Standards. Does annual mean every calendar year, or every 12 months? R8.3 should simply state "Test results shall be documented.". Lessons learned, etc are related to corporate and industry practices and are not part of reliability standards, otherwise there would need to be an entire standard for a corrective action process. R9 is not needed. The way this standard is written, there is NO allowable outage time permitted on either the primary or back up control center. As soon as one is unavailable the entity is immediately non-compliant. For an entity to continue to operate in non-compliance would be a significant exposure to penalties. What this standard really needs are requirements that describe the allowable outage time on the primary and back up control centers. The reality is that at some point every entity will need to disable one of their facilities so that maintenance can be conducted (whether it be planned or unplanned). Consider adding provisions for short term planned and unplanned outages on either the primary or back up control center.

Organization	Question 7:	Question 7 Comments:
		This would be similar to outage "time clocks" in the nuclear world. This would allow entities to make repairs and upgrades on the primary and back up control centers without automatically being non-compliant when conducting such activities.

Response: The primary control center is the facility normally used and the backup control center is used when the primary center becomes inoperable. The SDT does not see a contradiction between EOP-008-1 and the CIP standards. No change made.

“Prolonged” is the term used by FERC in Order 693 and was defined there as “generally defined by the time it takes to restore the primary control center”.

R1.2.4: BAL-005, R15 requires adequate and reliable power supplies to ensure uninterrupted operation of AGC. EOP-008 requires the backup operating plan to describe the power supply used to support the backup facility. The SDT does not feel a need to make changes to either standard.

R1.3: The intent of this sub-requirement is to keep the functionality used at the backup facility up to date with that used at the primary center.

R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity’s control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards~~ applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator’s primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality.

R6.1: The SDT has modified Requirement R6.1 for clarity.

R6.1 ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~.

Organization	Question 7:	Question 7 Comments:
R8: As the standard is written the annual test could be performed at any point during that year, not just within twelve months of the previous year's test R8.3: The requirement has been deleted. R9: The SDT has modified the wording to Requirements R4 & R5 to address this concern. See above.		
Sierra Pacific Power Co. (dba NV Energy)	Yes	In R1.3, a requirement is made to have a process for keeping the backup functionality "consistent" with the primary control center. The word "consistent" will be subject to much interpretation. Backup Control Centers inherently carry somewhat less functionality than the primary centers even though they may satisfy all of the compliance requirements with the Reliability Standards. In R2, we suggest a change in the language to say "…shall have its Operating Plan for backup functionality available to its System Operators at its primary control center?" This would allow for the use of electronic document management, as many entities have moved away from the tedious chore of maintaining hard-copy procedures in their control centers and should not be found non-compliant for using a progressive electronic document management solution. R3: It is unclear what is meant by directing BES operations through other entities, and what would constitute including "provisions for loss of those entities' control functionality". If for example, we direct BES operations through issuing switching instructions to a TO entity in our balancing area, do we become responsible for the loss of that TO's primary control center under this language? If this is the implication, we believe this Requirement is inappropriate. R4/R5: Why is there a conditional statement present in these Requirements ("…shall, during the time period when the primary control center functionality and the backup functionality are both available for use,…)? This literally states that this Requirement is inactive upon loss of the primary control center. After reading it several times, we continue to be unclear about the intent of that conditional statement. R6: We don't believe it is reasonable to require entities to update, approve, and keep necessary documentation for minor changes to backup facility plans for items such as "contact information". Phone numbers, fax, cell numbers, etc are all relatively dynamic, and should lie below the threshold of providing full plan updates. Perhaps this update/approval is needed for material changes to the Plan, Process or notification protocols, but minor, insignificant edits should not require this degree of documentation. R7: This specifies that the backup capability shall not depend on the "primary control center" for functionality to maintain compliance with the Standards. This is where much interpretation may arise. Most backup control facilities will have a fully redundant EMS computer, but it may depend on SCADA information that passes through the building which houses the primary control center. Such communications are outside the primary control center, yet in the same facility. Would this situation constitute a "dependency upon the primary control center, and if so, is the intent of this Requirement to expand beyond the confines of the "Primary Control Center" itself?

Organization	Question 7:	Question 7 Comments:
		R8.3: We suggest that it is unnecessary to document and incorporate into subsequent Plan revisions items that are characterized as "lessons learned". We should always be learning from test results and improving plans and processes, but as a compliance requirement, we believe this is onerous. Suggest replacement of the term "lessons learned" with "deficiencies", such that it reads "Test results shall be documented and deficiencies noted and incorporated in subsequent revisions of the Operating Plan for backup functionality".

Response: R1.3: intent of this sub-requirement is to keep the functionality used at the backup facility up to date with that used at the primary center.

R2: Measure M2 specifically allows for an electronic copy. No change made.

R3: The SDT has modified the wording of Requirement R3 to make it clear that the responsible entity must ensure that all entities with BES switching capability have backup functionality.

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.

R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less.

R4.2 Unplanned outages of the primary or backup facilities.

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

Organization	Question 7:	Question 7 Comments:
R6: The SDT agrees and contact information has been deleted. **R6.1** ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~. R7: The intent is that if the primary control center is destroyed, the backup facility will be capable of collecting the data needed to support the reliable operation of the BES. R8.3: The requirement has been deleted.		
Progress Energy Carolinas, Inc.	Yes	R5 — Compliance with all Reliability Standards should not be required immediately upon transition to the backup. The focus at immediate transition must be solely upon standards directly-related to essential BES reliability. This is evidenced within this standard by choosing an annual test only lasting 2 hours, which will only verify the basic functionalities of SCADA, alarming, voice & data communications, AGC, state estimator and contingency analysis. The requirement to immediately meet all standards causes undue time/finances to be spent on hot-backup technology for non-essential functions, and thus decreases attention to essential functions. Non-essential standard requirements such as inadvertent/interchange check-outs, TTC/ATC postings, transaction tagging, etc should be identified, and a longer transition requirement specified, such as 48 hours. R7 — How does this apply to a situation where primary EMS or voice communication equipment resides in a facility geographically separate from the primary center's control room? Does the phrase "does not depend on the primary control center" refers to the control room facility only, or does it also apply to the facility housing EMS/voice communication equipment? What distinguishes equipment for compliance to this standard versus CIP-009-1?
Progress Energy-Florida	Yes	R5 — Compliance with all Reliability Standards should not be required immediately upon transition to the backup. The focus at immediate transition must be solely upon standards directly-related to essential BES reliability. This is evidenced within this standard by choosing an annual test only lasting 2 hours, which will only verify the basic functionalities of SCADA, alarming, voice & data communications, AGC, state estimator and contingency analysis. The requirement to immediately meet all standards causes undue time/finances to be spent on hot-backup technology for non-essential functions, and thus decreases attention to essential functions. Non-essential standard requirements such as inadvertent/interchange check-outs, TTC/ATC postings, transaction tagging, etc should be identified, and a longer transition requirement specified, such as 48 hours. R7 — How does this apply to a situation where primary EMS or voice communication equipment resides in a facility geographically separate from the primary center's control room? Does the phrase "does not depend on the primary control center" refer to the control room facility only, or does it also apply to the facility housing EMS/voice communication

Organization	Question 7:	Question 7 Comments:
		equipment? What distinguishes equipment for compliance to this standard versus CIP-009-1?
Response: **R5:** Requirement R1.2 requires the plan to provide a summary description of the elements necessary to support the backup functionality. Requirement R1.6 requires the plan to provide a description of the actions to be taken during the transition period. The SDT did not intend to require a manned hot backup facility for BA's or TOP's. R7: The SDT has re-written the requirement to address these concerns and does not believe that presents a contradiction with CIP-009-1. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.		
NPCC	Yes	R3: It stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." We do not agree that this requirement applies to the TOP only. There might well be situations that an RC or a BA directs it operations through other entities as well. We suggest the requirement to also include the RC and the BA by rewording to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations?" R4: We are not sure why the condition: "…during the time period when the primary control center functionality and the backup functionality are both available for use…" is included since having both control center functionalities available for use suffice to meet the condition for: "?have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simply stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed, be eliminated, and include the required clarifications in the Measures Section. R5: Please see our comments on R4. We do not think R5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. R7: We do not see the need for this to be a stand alone requirement. This requirement can be included as one of the sub-requirement in R1, or even combined with R1.3.
Response: R3: The SDT agrees that this requirement should be extended. **R3.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that		

Organization	Question 7:	Question 7 Comments:
backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~. R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter. **R4.** Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~: **R4.1** Planned outages of the primary or backup facilities of two weeks or less **R4.2** Unplanned outages of the primary or backup facilities **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality R7. The SDT believes that this is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.		
Southern Company Transmission	Yes	**In reference to the Applicability Section 4.1, the following recommendation on the format is suggested:4.1.2 Transmission Operators that operate Facilities defined below: 4.1.2.1 Facilities operated at 200 kV or above 4.1.2.2 Non-radial Facilities operated at 100 kV 4.1.2.3 Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)In addition to the format change noted above, there could be a misinterpretation with use of the term 'critical' in this standard considering its significance to CIP-002? We suggest you consider the terms

Organization	Question 7:	Question 7 Comments:
		crucial, important, etc. as an alternative word for critical. **With respect to R1.1, an Operating Plan should include the location for providing backup functionality. There is a concern with how much specificity is required. If the Operating Plan becomes available to the public, the inclusion of the detailed location of a backup control center may unnecessarily create exposure to CEII information. **Requirement R1.1 does not clarify the meaning of "prolonged period of time." It is not clear if this means eight days or eight months for example. Should there be some correlation to Requirement R9, which provides that six months is the threshold for notifying the Regional Entity about restoration efforts? **The standard should consistently group sub-requirements under each of the relevant components ? Operating Plan, Operating Procedure, and Operating Process. As written, the arrangement is too scattered. Note the order of the requirements and how they are grouped: Requirements R1.1, R1.2, R1.5, and R1.7 correlate to the Operating Plan; Requirements R1.3 and R1.6 correlate to the Operating Process; and Requirement R1.4 correlates to Operating Procedures. The following recommendations ensure more consistency:(a) Insert R1.7 after R1.2 since R1.7 addresses identification of roles for the Operating Plan. It should not be the last item. **R1.5 should be put under R1.6 as a sub-requirement. Also reword the requirement to say The transition period between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running must not exceed two hours. **Under R3, it is unclear as to what the requirement is stating. Are you saying that a registered entity that is relying entirely on other entities to perform the TOP function is also responsible for making sure their Operating Plan provides provisions for the loss of each of the other entities' control functionality? Are there such "Pseudo TOPs" out there that this describes? Clarification would be good for Industry.

Response: Based on your comment and many others, the SDT has decided to remove all qualifying language from 4.1.2 and list only "Transmission Operator." We believe, and in addition are convinced by comments received, that the NERC "Statement of Compliance Registry Criteria (Revision 5.0)" and Section 501 (specifically Section 501 1.2.3) of the NERC Rules of Procedure satisfactorily addresses which entities should be registered as a TOP, and therefore, subject to the applicable provisions of this standard. The standards drafting process is not the appropriate venue for addressing inconsistency issues regarding the REs. This should be addressed directly with the REs, or if necessary, with NERC or FERC.

4.1.2 Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.

R1.1: a.: The SDT does not consider Operating Plans to be public material.

Organization	Question 7:	Question 7 Comments:
b.: "Prolonged" is the term used by FERC in Order 693 and was defined there as "generally defined by the time it takes to restore the primary control center" The SDT does not plan to reorganize the standard format as it would not add any clarity at this time. R1.5 The SDT has re-worded R1.5 for clarity. **R1.5** A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours. R3 has been re-written to provide clarity surrounding the SDT's intent. **R3.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.		
Xcel Energy	Yes	R1.5 Please clarify what you mean by "fully implement" and "get backup functionality up and running". As written, this requirement is too vague. Related to R1.5, please modify M1 to include clarifying language such as "functionality required for maintaining compliance".R1.2.1 Please clarify what is meant by "visualization capabilities". This statement is too vague and leaves too much room for interpretation. R1.3 Please clarify what is meant by "consistent". What processes need to be covered? This requirement is too vague and general, which leaves too much room for interpretation.R1.6 Please clarify/outline what minimum actions are required during the transition period. R1.6.2 To be more clear, we recommend changing "risk" to "impact". R5 As drafted, this requirement implies that both the primary and backup control centers have to be in operation at the same time. This is not practical, as only one control center can communicate with the RTUs. This requirement should be reworded. R6.1 Strike "contact information". This is not necessary to include in the requirement. R8.2 Testing for a minimum of 2 continuous hours is unnecessary and problematic b/c we would lose accounting data which affects our CPS reporting data. A minimum test of 30 minutes is reasonable and sufficient. Please either modify to 30 minutes or provide a factual basis for the 2 hours.
Response: R1.5: The intent is to define the transition period as the time from the loss of the primary control center to the time the operator at the backup location can perform monitoring and control. Measure M1 was re-written to provide greater clarity. **R1.5** A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal		

Organization	Question 7:	Question 7 Comments:

to ~~plan and get backup functionality up and running that is less than~~ two hours.

M1. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format. ~~, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable~~.

R1.2. 1: All facilities needed to display required operational information are considered visualization capabilities.

R1.3: The intent of this sub-requirement is to keep the functionality used at the backup facility up to date with that used at the primary center.

R1.6 The SDT has re-written this requirement to provide greater clarity.

R1.6 An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time ~~to~~ to fully implement the backup functionality elements identified in Requirement R1.2~~get backup functionality up and running~~. The Operating Process shall also include:

R1.6.2: The SDT believes that managing risk is a broader term and more appropriate for this requirement.

R4/5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards~~ applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

Organization	Question 7:	Question 7 Comments:
R6.1: The SDT clarified Requirement R6.1. **R6.1** ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~. R8.2: The SDT wanted the test to run across an hour boundary to ferret out exactly these types of problems which need to be fixed in order to be compliant.		
Entergy Services, Inc	Yes	The terminology in R1.1 "for a prolonged period of time" is too vague. Please be more specific. The TOP situation indicated in R3 is unclear. What is the arrangement of a TOP directing BES operations through other entities? Is it envisioned that the TOP might be using, say, the RCs control center to run the TOP's BES? Please change the language so the applicability of this requirement is obvious. The rewording of R4 and R5 is confusing. Instead of trying to include all the ideas into one sentence, it would be better and more clear to include a couple of separate sentences. For instance, we suggest for R4, and similar wording for R5:" R4. Each Reliability Coordinator shall have a backup control center facility that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator. This functionality may be provided through its own dedicated backup facility or at another entity's control center. If the loss of the primary or backup capability has already been experienced, a second backup facility is not immediately necessary, i.e., double redundancy is not necessary."
Response: "Prolonged" is the term used by FERC in Order 693 and was defined there as "generally defined by the time it takes to restore the primary control center" R3 has been re-written to provide clarity surrounding the SDT's intent. **R3.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~. R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter. **R4.** Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~		

Organization	Question 7:	Question 7 Comments:
		that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~: **R4.1** Planned outages of the primary or backup facilities of two weeks or less. **R4.2** Unplanned outages of the primary or backup facilities. **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less. **R5.2** Unplanned outages of the primary or backup functionality.
Duke Energy	Yes	Detailed edits - see revisions in CAPS below: R1 - Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have an Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center FUNCTIONALITY becomes inoperable. This Operating Plan for backup functionality shall include the following at a minimum: R1.1 - The location and method of implementation for providing backup functionality for a prolonged period of time, AS DEFINED BY THE OPERATING PLAN. R1.2.5 - Physical and cyber security. SDT SHOULD DELETE THIS REQUIREMENT SINCE IT IS COVERED IN THE CIP STANDARDS REQUIREMENTS. R1.3 - An Operating Process for keeping the backup functionality consistent with the primary control center FUNCTIONALITY. R3 - Question : What is an entity? More importantly, what is NOT an entity? R4 and R5 - COMBINE THESE TWO REQUIREMENTS INTO ONE AS FOLLOWS: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator shall, during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality (such as monitoring, control, logging and alarming) needed to maintain compliance with all applicable Reliability Standards".

Organization	Question 7:	Question 7 Comments:
		R6.1 - The update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to the backup FUNCTIONALITY AS DEFINED IN R1.2. R7 - Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have backup FUNCTIONALITY that does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards. R9 - Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of its primary or backup FUNCTIONALITY and that anticipates that the loss of primary or backup FUNCTIONALITY will last for more than six calendar months, shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup FUNCTIONALITY. M1 - Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center FUNCTIONALITY becomes inoperable. M4/M5 - Language needs to match exclusions included in R4/R5. Same clean up as noted in R4/R5 comments aboveM7 - See comment on R7 aboveM9 - See comment on R9 above

Response: R1 & R1.3: The intent of the standard is to have backup capability for loss of the PCC including all facilities and functionality. Therefore, the SDT sees no need for a wording change.

R1.1: The proposed wording is redundant. Therefore, the SDT feels there is no need to change the wording.

R1.2.5: The SDT feels this should be part of the Operating Plan even if reference is made to another document.

R3: An “entity” is the term used in the NERC functional model.

R4 & 5: Because the backup requirement is different for RC and BA/TOP it is necessary to have two requirements that address the differences.

R6.1: The SDT has made a change to provide clarity.

R6.1 ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~.

R7: The proposed wording doesn’t seem to change anything. Therefore, the SDT feels there is no need to change the wording.

R9: The intent of the standard is to have backup capability for loss of the PCC including all facilities and functionality. Therefore, the SDT sees no need for a

Organization	Question 7:	Question 7 Comments:
wording change. M1: The SDT did not change Requirement R1 as suggested so there is no change to Measure M1 for this comment. M4 & M5: It is unclear as to what "exclusions" are referred to so the SDT made no changes. M7: Since no change is made to R7 from this comment, no change is necessary to Measure M7. The SDT believes that Requirement R7 is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~. M9: Since no change is made to Requirement R9 as suggested, no change is necessary to Measure M9.		
Electric Reliability Council of Texas, Inc.	Yes	R1.2: The word "overview" seems to allow a lot of room and the measure (M1) does, too. However, when it comes to audit time, how specific might the auditor think it needs to be? R3: While ERCOT is the registered Transmission Operator in the region, it does not have direct control over the control facilities of all transmission operators and Qualified Scheduling Entities in ERCOT. ERCOT's Protocols and Operating Guides which require those entities to have and maintain backup facilities. Compliance with those requirements is monitored by ERCOT and the Texas Regional Entity. If ERCOT's Operating Plan would be considered to be in compliance based on references to such Protocol and Operating Guide requirements, rather than detailed provisions for each of the other entities, then this requirement is acceptable. Otherwise, it should be revised to accommodate such a method of compliance. R4 and R5: Is this just a way to say that there is no requirement to have a backup to the backup facility in the event that the primary control center functionality is lost? It also seems to say that when both primary and backup are available, the RC, BA and TO have to also have a Backup Control Center Facility. This requirement needs some simplified wording to make its intent more clear. Maybe using more than one sentence would help.R7: Should be part of R1R8.3: add "as necessary" between "incorporated" and "in" R9: Why six months to provide something that should be in place all the time?
Response: R1.2: The SDT changed the wording to provide greater clarity. **R1.2** An ~~overview~~ summary description of the elements required to support the backup functionality. Requirement R3 has been re-written to provide clarity surrounding the SDT's intent.		

<table>
<tr><th>Organization</th><th>Question 7:</th><th>Question 7 Comments:</th></tr>
<tr><td colspan="3">

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.

R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

R7. The SDT believes that this is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT.

R7. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.

R8.3: The requirement has been deleted.

R9: The reasons for the loss of the PCC are numerous and have an impact on the replacement of the PCC. Therefore, the SDT feels it necessary to give the RC, BA, or TOP time to evaluate the replacement and plan it. Six months seems adequate.

</td></tr>
<tr><td>MRO NERC Standards</td><td>Yes</td><td>R1, Requires that applicable entities have an Operating Plan covering "backup functionality". Then R1.1 uses "backup functionality" as a sub-requirement to R1, without explaining what "backup functionality" is. Would a Balancing Authority's</td></tr>
</table>

Organization	Question 7:	Question 7 Comments:
Review Subcommittee		backup functionality be all NERC requirements assigned to a Balancing Authority? Please define.R1.5, What happens if the applicable entity needs more than two hours to get "backup functionality" running? R1.6.2, Does "?as well as during outages of the primary/backup functionally" include SCADA, Energy Managements Systems, etc., updates? Could the SDT clarify the maximum amount of time that updates, patches, maintenance could take place without harming the BES, such as within one hour? R2, states the Operating Plan is required to be " at the location supporting backup functionally". If this is the backup control center, the MRO agrees, if not please clarify. R4, The MRO believes this requirement is redundant and should be removed. The MRO believes that this requirement would put the RC in double jeopardy. Please clarify why R4 is written. R5, The MRO believes this requirement is redundant and should be removed. The MRO believes that this requirement would put the BA & TOP in double jeopardy. Please clarify why R5 is written.

Response: R1: Your interpretation is correct.

R1.5: If you 'need' more than 2 hours, you would have to discuss the issue with your RE.

R1.6.2: The assumption is correct. Also, the SDT has not defined a max time for maintenance because maintenance time depends on the scope of the maintenance required.

R2: This can be the backup control center or a backup location where the functionality is contracted.

R4 & R5: The SDT does not understand what this would be redundant with as no specificity was provided but changes have been made to Requirements R4 & R5 due to other comments.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority

Organization	Question 7:	Question 7 Comments:
and Transmission Operator's primary control center functionality respectively.~~,~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality		
ITC	Yes	Requirement 3 should be re-worded to "Each applicable Transmission Operator "delegating" BES "operational functions to" other entities? At any given time, the TOP may 'direct' any connected GOP or LSE to take an action to support BES operations. As written, this requirement could be interpreted to require the TOP to have the backup plan for all connected GOPs, LSEs, etc. incorporated into their plan. Limiting the scope to those functions which are formally delegated is more appropriate and reasonable. Requirement 4 and 5 should be reworded. The requirement is cumbersome to read and understand. We believe the intent of the phrase "during the time period when the primary control center functionality and the backup functionality are both available for use" is intended to clarify that if you are already at your backup, you are not required to have a second N-2 backup. We suggest you add a sub-requirement that clearly states this exclusion and remove the phrase from the main requirement. Requirement 6 should be a sub-requirement of requirement 1 and requirement 6 and 6.1 should be combined into a single requirement that says the plan must be updated annually OR within 60 days of any significant changes. Requirement 7 is unnecessary and ambiguous. Requirement 1 adequately addresses the specific requirements of the Plan. Requirement 9 should be modified. If extended operation from a backup facility is a real concern to reliability, the RE should not be waiting 6 months to know there is an alternative plan. If it's OK to wait 6 months, this requirement should be removed.
Response: R3 has been re-written to provide clarity surrounding the SDT's intent. **R3.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~. R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter. **R4.** Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~		

Organization	Question 7:	Question 7 Comments:
that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~: **R4.1** Planned outages of the primary or backup facilities of two weeks or less **R4.2** Unplanned outages of the primary or backup facilities **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality R6: The SDT feels Requirement R6 should be a separate requirement because it does not deal with the Plan contents. The SDT also feels the sub-requirement details the update and approval requirements and should be separate from the requirement. R7: The intent is that if the primary control center is destroyed, the backup facility will be capable of collecting the data needed to support the reliable operation of the BES. R9: The reasons for the loss of the PCC are numerous and have an impact on the replacement of the PCC. Therefore, the SDT feels it necessary to give the RC, BA, or TOP time to evaluate the replacement and plan it. Six months seems adequate.		
Western Area Power Administration	Yes	Requirement #1.6.2; Change "Actions to manage the risk?" to "Actions to manage the impact?" Requirement #3; Please specify the meaning of "?directing BES operations through other entities?" What does through other entities mean? Requirement #5; "during the time period when the primary control center functionality and the backup functionality are both available for use, have backup functionality?" This statement is very vague and implies having two control centers in operation at all times. This sentence needs to be rewritten. Requirement #5; "maintaining compliance with all Reliability Standards?" is too vague. Please specify the Reliability Standards required for compliance. Requirement#6.1; Timing on an updated Operating Plan is vague. A suggestion is to state the updated Operating Plan should be within 12 months from the last update. Requirement #8.3; Lessons learned should not be included in the Operating Plan. A suggestion is to have the lessons

Organization	Question 7:	Question 7 Comments:
		learned as evidence resulting from the tests.

Response: R1.6.2: The SDT believes that managing risk is a broader term and more appropriate for this requirement.

Requirement R3 has been re-written to provide clarity surrounding the SDT's intent.

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.

R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

R6.1: The SDT has made a change to provide clarity.

R6.1 ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~.

R8.3: The requirement has been deleted.

ISO New	Yes	R3: It stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include

Organization	Question 7:	Question 7 Comments:
England Inc		provisions for the loss of such entity’s control functionality in its Operating Plan for backup functionality." We do not agree that this requirement applies to the TOP only. There might well be situations that an RC or a BA directs it operations through other entities as well. We suggest the requirement to also include the RC and the BA by rewording to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations?" R4: We are not sure why the condition: "…during the time period when the primary control center functionality and the backup functionality are both available for use…" is included since having both control center functionalities available for use suffice to meet the condition for: "?have a backup control center facility (provided through its own dedicated backup facility or at another entity’s control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simply stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed. R5: Please see our comments on R4. We do not think R5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. R7: We do not see the need for this to be a stand alone requirement. This requirement can be included as one of the sub-requirement in R1, or even combined with R1.3.
Hydro-Québec TransÉnergie (HQT)	Yes	R3: It stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity’s control functionality in its Operating Plan for backup functionality." We do not agree that this’’ requirement applies to the TOP only. There might well be situations that an RC or a BA directs it operations through other entities as well. We suggest the requirement to also include the RC and the BA by rewording to: "Each Reliability Coordinator, Balancing’’ Authority and applicable Transmission Operator directing BES operations?" R4: We are not sure why the condition: "?during the time period when the primary control center functionality and the backup functionality are both available for use?" is included since having both control center functionalities available for use suffice to meet the condition for: "…have a backup control center facility (provided through its own dedicated backup facility or at another entity’s control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simply stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed, be eliminated, and include the required clarifications in the Measures Section. R5: Please see our comments on R4. We do not think R5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability'sfunctionality.R7: We do not see the need for this to be a stand alone requirement. This requirement can be included as one of the sub-requirement in R1, or even combined with R1.3.In regard to R7, we

Organization	Question 7:	Question 7 Comments:
		would appreciate the SDT to indicate if the EMS system should be doubled also at the Backup facility since R7 specifies that the Backup "does not depend on the primary control center for any functionality required to maintain compliance with Reliability Standards.".

Response: Requirement R3 has been re-written to provide clarity surrounding the SDT's intent.

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.

R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirement R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

R7: Requirement R7 is intended to provide clarity and remove ambiguity as it pertains to implementation of backup control functionality. The SDT believes that the requirement should remain. The SDT believes that this is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. Duplicate EMS functionality may be required to ensure no dependency on the primary control center.

Organization	Question 7:	Question 7 Comments:
Independent Electricity System Operator	Yes	R3: We have two comments on this Requirement: a. It stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." We do not agree that this requirement applies to the TOP only. There might well be situations that an RC or a BA directs its operations through other entities as well. We suggest the requirement to also include the RC and the BA by rewording to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations?" b. We believe the wording is ambiguous in that in some areas/jurisdictions, there are multiple TOPs that one of them direct the operations of the other. For example, an ISO is registered as a TOP while a transmission entity (an owner, for example) within the ISO footprint is also registered as a TOP. The two TOPs perform distinctly different tasks and may even have their tasks and responsibilities clearly stipulated in an agreement, market rule or regional reliability plan. The ISO-TOP directs operations of the transmission-entity-TOP while the latter may be solely responsible for switching operations and maintenance. Both need to have backup capability. The way R3 is worded can be interpreted that the ISO-TOP needs to be responsible for the backup capability of the transmission-entity-TOP. We do not believe this is the intent of R3, and this is not acceptable. To clarify this situation, we suggest R3 to be reworded to: Each applicable Transmission Operator delegating its tasks for BES operations to other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality. In other words, this requirement only applies to a TOP if it delegates it task (for which it is still fully responsible) to another entity. R4: We are not sure why the condition: "…during the time period when the primary control center functionality and the backup functionality are both available for use…" is included since having both control centre functionality available for use suffice to meet the condition for: "…have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simple stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed. R5: Please see our comments on R4. We do not think R5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. R7: We do not see the need for this to be a stand alone requirement. This requirement can be included as one of the sub-requirement in R1, or even combined with R1.3.

Response: R3a **–** Requirement R3 has been re-written to provide clarity surrounding the SDT's intent.

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that

Organization	Question 7:	Question 7 Comments:
backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~. R3b – Each TOP is independently responsible for meeting the standard. Joint registration agreements may have an impact here. R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter. **R4.** Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~: **R4.1** Planned outages of the primary or backup facilities of two weeks or less **R4.2** Unplanned outages of the primary or backup facilities **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality R7. The SDT believes that this is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.		
Pepco Holdings, Inc. - Affiliates	Yes	The requirements should be modified to recognize that duplicate and separate EMS facilities running in parallel without dependence on each other fulfill the need for backup facilities.
Response: The SDT believes that the primary and backup capabilities should be independent. The SDT believes that Requirement R7 is a standalone		

Organization	Question 7:	Question 7 Comments:
requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.		
ReliabilityFirst Corporation	Yes	In R1.3, I am not sure what "Operating Process" means. I am thinking may be you can say "Back-up Control Facility Operating guide". Also suggest replacing "backup functionality" with "backup control functionality". I feel this conveys the intent better.
Response: The term "Operating Process" is a defined term.		
PJM Interconnection	No	PJM's concerns center on the basic premise of the standard; that there is one "primary" facility, and one "backup" facility. With the completion of our Business Continuity plan, PJM will be operated simultaneously from our existing control center, and another fully staffed, redundant center at a remote location (neither facility will be designated "primary" or "backup").In the event of the loss of one of these facilities, this type of operation will accommodate an instantaneous transfer of all control to the redundant center. For this reason, PJM would like to propose the following addition to the applicability section of the standard 4.2. EOP-008-1 shall not apply to Reliability Coordinators, Transmission Owners, or Balancing Authorities that operate two equal, real-time facilities, at geographically diverse sites, either of which is capable of operating as a stand alone, fully functional data center and control center. PJM feels that this type of redundant operation goes far beyond the requirements in the current standard, to ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable. The very narrow exemption provided in the proposed addition is the cleanest. Simplest way to accommodate this scenario If the SDT does not agree to the proposed addition to the applicability section, PJM's representative will deliver a redline version of the current draft of the standard to the group at their next meeting. This will have a requirement by requirement, measure by measure, list of all the changes that allow for this type of redundant operation to meet all compliance scrutiny. A copy of this document has been forwarded to Ed Dobrowolski of the NERC office. Beyond this PJM submits the following for consideration: In Applicability 4.1.2, the SDT creates a new class of TOP. This is beyond the Scope of the Standard. 4.1.2 can only apply to current registered entities. PJM would like to strike "allow visualization capabilities that" in R1.2.1. Tools for visualization are not in the requirements for any primary control center. Seems inappropriate to be in the requirements for a backup. Suggest changing R1.2.5 to read "All applicable NERC CIP Standards Suggest adding "unless this change is functionally

Organization	Question 7:	Question 7 Comments:
		transparent to the users" to the end of R1.6.1. PJM is aware of several Local Control Centers that have telephone & data switching that is done by a central station. No contact information changes, and the caller should be indifferent to the physical location of the receiver. R3 would require TOPs directing BES operations through other entities to be accountable for the compliance of all of these entities. If this is the intent of the SDT, the Applicability section of the standard needs to be modified to include Transmission Owners (TOs) in lieu of defining other applicable entities in R3. In R5, Monitoring, control, logging, and alarming should all be sub-bullets of R5 (as done in R1.6 "Process shall include"
Response: The SDT believes that EOP-008 is applicable to all registered Reliability Coordinators, Transmission Operators, and Balancing Authorities. Redlined document: The SDT has reviewed the redlined document. There were no changes other than those suggested for the applicability change mentioned in the first paragraph of the comment. Since that change was not made, none of the redlined comments apply. R1.2.1: All facilities needed to display required operational information are considered visualization capabilities. The SDT considers this an important element for reliability and believes it needs to remain in the requirements. R1.2.5: The SDT has reviewed your suggestion and believes that the current wording is appropriate. R1.6.1: The SDT does not understand the comment as applied to Requirement R1.6.1 so no change has been made. R3: R3 has been re-written to provide clarity surrounding the SDT's intent. **R3.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~. R5: The SDT reviewed this suggestion and didn't feel that it substantially changed the requirement so no change has been made.		
Ameren	Yes	Requirement 2 is not needed. What is important is that the plan gets implemented when needed not that some compliance auditor can verify there is a copy of the plan at the backup and primary control centers. Most entities are going to have their plans at the primary and backup control centers to allow them to implement the plan. If they don't, they likely won't be able to implement their plan in the required time frame. Thus, they will already be violating another requirement so let's not provide an opportunity for double jeopardy. Requirement 4 should strike "that provides functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator". The RC is already required to comply with these standards regardless of whether they operate from the backup center or the primary center.

Organization	Question 7:	Question 7 Comments:
		Requirement 5 should strike "sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority or Transmission Operator respectively". The BA and TOP are already required to comply with these standards regardless of whether they operate from the location of their backup capability or the primary center. Further, we urge the drafting team to consider combining requirements 4 and 5 to require full backup control centers for the TOP and BA as well as the RC. Requirement 5 is already stringent enough that a backup control center is likely required anyway. Combining the requirements just simplifies the standards. Requirement 6 is really a sub-requirement of requirement 1. Sub-requirement 6.1 is confusing. Because it is a sub-requirement, it must apply to requirement 6. Thus, it would seem that the sub-requirement is requiring the annual review and approval to occur within 60 days of any changes. What if there are multiple changes in the year? From this perspective, it appears that the sub-requirement is intended to reflect that changes can occur at any time. To clarify the requirement, we suggest the following language as a sub-requirement of R1 along with striking requirement 6 and 6.1:"Each RC, BA an TOP shall review and approve its Operating Plan for backup functionality annually and within sixty calendar days of any changes to the backup location, capabilities or contact information, modify the Operating Plan to reflect the changes." Requirement 7 is unnecessary as an explicit requirement. Each RC, TOP and BA is required to comply with all applicable requirements even if they are operating from the location of their backup functionality or backup control center. If their backup functionality relies on the primary control center, the RC, TOP and BA will be unable to comply with numerous other requirements in the event that they lose the functionality of their primary control center. Requirement 8 is not needed and does not accomplish the goal of ensuring the backup capability is available when needed. In reality, an RC, TOP and BA will have to operate utilizing backup functionality significantly more often than annually to ensure that backup functionality is available when needed. In fact, most RC, TOP, and BA already test their backup capability more often than annually even though the current requirement is for an annual test. They do this not because of the testing requirement but because of the need to continue to comply with other applicable requirements. If the other standards requirements already drive the entities to exceed this requirement, why is it needed? It is not. Requirement 9 should be struck. This requirement essentially represents an N-2 condition. The requirements should not try to anticipate extreme conditions such as this. Because RC, TOP and BA are still required to comply with the requirements even if they lose one of the operating centers or backup capability, the RC, TOP and BA will have to make plans to operate in the event of the failure of their last operable control center. Thus, failure to begin developing a plan to replace the backup capability or primary control center will surely result in a violation of another requirement (actually likely many requirements).

Response: R2 is intended to provide clarity and remove ambiguity as it pertains to the implementation of backup control functionality. R2 will also ensure that the plan will be readily available to assist personnel during an actual event. The SDT believes that the requirement should remain.

Organization	Question 7:	Question 7 Comments:
R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter. **R4.** Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards~~ applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~: **R4.1** Planned outages of the primary or backup facilities of two weeks or less **R4.2** Unplanned outages of the primary or backup facilities **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality R6: Requirement R1 addresses the content of the plan, while Requirement R6 addresses the timeliness of reviews and updates. Therefore, no change was made. R7/R8: Requirements R7 and R8 are intended to provide clarity and remove ambiguity as they pertain to implementation of backup control functionality. . **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control center functionality~~.~~. R9: The SDT believes this requirement adds clarity in the event of a catastrophic failure of either its primary facility or backup capability.		
FirstEnergy Corp.	Yes	Requirement R1.6.2 is not clear. The meaning of primary/backup is ambiguous. This requirement should be revised to state, "Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during simultaneous outages of both the primary and backup functionality." Requirements R4 and R5 as written are very confusing. It appears the drafting team's expectation is for an entity to have either the primary or backup control center available and in use at all times. If that is the intent, the requirement should say that. Also, it appears the drafting team's expectation is compliance with all applicable Reliability Standards at all times. This

Organization	Question 7:	Question 7 Comments:
		is a requirement of the mandatory and enforceable reliability standards. R4 and R5 should be deleted. Requirement R6 as written is confusing. Who is intended to approve the Operating Plan for the backup functionality? Is it the intent of the drafting team for each entity to approve its own plan? Should these plans be required to be approved by a senior executive of the company? Should these plans be approved by the RC? Requirement R9 should be revised to state, “Each Reliability Coordinator, Balancing Authority, and applicable Transmission Operator that has experienced a loss of either its primary or backup capability due to a catastrophic event and anticipates the loss of either its primary or backup capability will last for more than six calendar months, shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability.” This requirement as currently proposed allows an entity 6 months to restore its backup functionality. Backup functionality should be restored as soon as repairs can be made in most cases. Only in a catastrophic event should an entity be allowed to be without backup for such a long period of time. Requirement 7 is unnecessary. If a RC, TOP and BA, can comply with all applicable requirements at all times from a backup control center that relies on facilities of their primary control center, then they have met the intent of the standards.

Response: R1.6.2: The SDT rewrote Requirement R1.6.2 to provide clarity but believes that covering simultaneous outages is not required.

R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary~~/~~ or backup functionality. .

R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority

Organization	Question 7:	Question 7 Comments:
and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R5.1** Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality R6: Each entity would determine who from their utility would be the appropriate signature. The SDT cannot determine who that might be for every registered entity. It is not the intent of the SDT that each entity's plan be approved by their respective RC. R7. The SDT believes that this is a standalone requirement as Requirement R1 covers the plan and Requirement R7 the capabilities. However, Requirement R7 has been re-written to provide additional clarity as to what was the intent of the SDT. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~. R9: The SDT believes that primary or backup functionality should be restored when reasonably practicable after an event. The intent of this requirement is to have a plan within 6 months for major outage situations.		
Bureau of Reclamation	Yes	In requirement R1.1 the term "for a prolonged period of time" has been added. As this is a nebulous addition that does not add clarification to the requirement it should be deleted. Requirement R3 requires the TOP when "…directing BES operations through other entities…" to "include provisions for the loss of such other entity's control functionality in its Operating Plan for backup functionality." We agree with this requirement, however, there is no requirement for such provision to ever be coordinated with the other entity, or for the other entity to even be informed. We suggest adding to R3 or R6, language similar to: "Those provisions in the Operating Plans for backup functionality that deal with the loss of another entity's control functionality shall be coordinated with that entity when the Operating Plans are reviewed annually."
Response: "Prolonged" is the term used by FERC in Order 693 and was defined there as "generally defined by the time it takes to restore the primary control center" Requirement R3 has been re-written to provide clarity surrounding the SDT's intent which should alleviate your concern. **R3.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.		

Organization	Question 7:	Question 7 Comments:
ISO/RTO Council	Yes	We do not agree with the transition requirement of two hours. We believe that the transition time as worded in the existing standard actually requires full implementation of the backup plan in one hour or to provide an alternative to continue operations. Thus, we assume the drafting team must have had a compelling reason for changing to two hours. What is the reason? Is there data justifying it? We recommend changing it back to one hour. Requirement 2 is not needed. What is important is that the plan gets implemented when needed not that some compliance auditor can verify there is a copy of the plan at the backup and primary control centers. Most entities are going to have their plans at the primary and backup control centers to allow them to implement the plan. If they don't, they likely won't be able to implement their plan in the required time frame. Thus, they will already be violating another requirement so lets not provide an opportunity for double jeopardy. Requirement 3 stipulates that "Each applicable Transmission Operator directing BES operations through other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." We do not agree that this requirement should apply to the TOP only. There might well be situations that an RC or a BA directs it operations through other entities as well. We suggest the requirement should also include the RC and the BA by rewording the requirement to: "Each Reliability Coordinator, Balancing Authority and applicable Transmission Operator directing BES operations?" Wording of requirement 3 is ambiguous in that in some areas/jurisdictions, there are multiple TOPs that one of them directs the operations of the others. For example, an ISO is registered as a TOP while a transmission entity (an owner, for example) within the ISO footprint is also registered as a TOP. The two TOPs perform distinctly different tasks and may even have their tasks and responsibilities clearly stipulated in an agreement, market rule or regional reliability plan. The ISO-TOP directs operations of the transmission-entity-TOP while the latter may be solely responsible for switching operations and maintenance. Both need to have backup capability. The way R3 is worded can be interpreted that the ISO-TOP needs to be responsible for the backup capability of the transmission-entity-TOP. We do not believe this is the intent of R3, and this is not practical. To clarify this situation, we suggest R3 to be reworded to: "Each applicable Transmission Operator delegating its tasks for BES operations to other entities shall include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality." In other words, this requirement only applies to a TOP if it delegates it task (for which it is still fully responsible) to another entity. For Requirement 4, we are not sure why the condition: "?during the time period when the primary control center functionality and the backup functionality are both available for use?" is included since having both control center functionality available for use suffice to meet the condition for: "?have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) that provides the functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator." If the intent of this requirement is to ensure the functionality works, then the requirements should simply stipulate such a demonstration. In fact, the intent of R8 is to ensure that the backup capability is functional when called upon. We therefore hold the view that R4 (and R5) is not needed. We further do not understand the clause "that provides functionality required for maintaining compliance with all Reliability Standards

Organization	Question 7:	Question 7 Comments:
		applicable to the Reliability Coordinator". The RC is already required to comply with these standards regardless of whether they operate from the backup center or the primary center. Requirements should never require compliance with other requirements because it creates the opportunity for double jeopardy. For Requirement 5, please see our comments on regarding Requirement 4. We do not think Requirement 5 is needed. If retained, the wording should be changed to require a demonstration of the backup capability's functionality. Furthermore, we don't understand the need for the statement "sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority or Transmission Operator respectively" in the requirement. The BA and TOP are already required to comply with these standards regardless of whether they operate from the location of their backup capability or the primary center. Requirement 6 is really a sub-requirement of requirement 1. Sub-requirement 6.1 is confusing. Because it is a sub-requirement, it must apply to requirement 6. Thus, it would seem that the sub-requirement is requiring the annual review and approval to occur within 60 days of any changes. What if there are multiple changes in the year? From this perspective, it appears that the sub-requirement is intended to reflect that changes can occur at any time. To clarify the requirement, we suggest the following language as a sub-requirement of R1 along with striking requirement 6 and 6.1:"Each RC, BA an TOP shall review and approve its Operating Plan for backup functionality annually and within sixty calendar days of any changes to the backup location, capabilities or contact information, modify the Operating Plan to reflect the changes." Requirement 7 is unnecessary as an explicit requirement. Each RC, TOP and BA is required to comply with all applicable requirements even if they are operating from the location of their backup functionality or backup control center. If their backup functionality relies on the primary control center, the RC, TOP and BA will be unable to comply with numerous other requirements in the event that they lose the functionality of their primary control center. Requirement 8 is not needed and does not accomplish the goal of ensuring the backup capability is available when needed. In reality, an RC, TOP and BA will have to confirm that availability of their backup functionality significantly more often than annually to ensure that backup functionality is available when needed. In fact, most RC, TOP, and BA already confirm the availability of their backup capability more often than annually even though the current requirement is for an annual test. They do this not because of the testing requirement but because of the need to continue to comply with other applicable requirements. If the other standards requirements already drive the entities to exceed this requirement, why is it needed? It is not. Requirement 9 should be struck. This requirement essentially represents an N-2 condition. The requirements should not try to anticipate extreme conditions such as this. Because RC, TOP and BA are still required to comply with the requirements even if they lose one of the operating centers or backup capability, the RC, TOP and BA will have to make plans to operate in the event of the failure of their last operable control center. Thus, failure to begin developing a plan to replace the backup

Organization	Question 7:	Question 7 Comments:
		capability or primary control center will surely result in a violation of another requirement (actually likely many requirements).

Response: The SDT believes two hours was broad enough to capture the very different business/risk decisions that have been made in the past regarding backup control centers (weighing the value of greater geographic separation over the need for rapid response), but also tight enough for entities to develop mitigations to address the maximum two hour transition period. The SDT believes that the new standard has significantly moved beyond the old standard (original Version 0, R1.8) by requiring immediate management of the risks

R2: Requirement R2 is intended to provide clarity and remove ambiguity as it pertains to the implementation of backup control functionality. R2 will also ensure that the plan will be readily available to assist personnel during an actual event. The SDT believes that the requirement should remain.

Requirement R3 has been re-written to provide clarity surrounding the SDT's intent.

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~.

R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

R6: Requirement R1 addresses the content of the plan, while Requirement 6 addresses the timeliness of reviews and updates. Therefore, no change was

Organization	Question 7:	Question 7 Comments:
made. R6.1 was changed to provide clarity. **R6.1** ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~. R7/R8: Requirements R7 and R8 are intended to provide clarity and remove ambiguity as they pertain to implementation of backup control functionality. The SDT believes that the requirements should remain but has revised Requirement R7 in an attempt to provide clarity. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~. R9: The SDT believes that primary or backup functionality should be restored when reasonably practicable after an event. The intent of this requirement is to have a plan within 6 months for major outage situations.		
Northeast Utilities	Yes	The revised language in R4 and R5 does not clarify the intent, which we believe is to prevent a violation for not having a backup facility during the time period when it has become necessary to utilize the backup facility. i.e. - that a backup for the backup is not required. We believe this clarification is not needed as separate requirements and results in confusing text. One possible solution would be to eliminate R4 & R5 and include the clarifying thoughts in the Measures. R7 includes the necessary language from R4 & R5, and could be included as one of the sub-requirements in R1, or combined with R1.3.
Response: R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified R4 & R5 to provide clarity on this matter. **R4.** Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~: **R4.1** Planned outages of the primary or backup facilities of two weeks or less **R4.2** Unplanned outages of the primary or backup facilities **R5.** Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required		

<table>
<tr><th>Organization</th><th>Question 7:</th><th>Question 7 Comments:</th></tr>
<tr><td colspan="3">during:

R5.1 Planned outages of the primary or backup functionality of two weeks or less

R5.2 Unplanned outages of the primary or backup functionality

R7: Requirement R7 is intended to provide clarity and remove ambiguity as it pertains to implementation of backup control functionality. The SDT believes that the requirement should remain but has revised Requirement R7 in an attempt to provide additional clarity.

R7. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~.</td></tr>
<tr><td>Midwest ISO</td><td>No</td><td>Requirement 2 is not needed. What is important is that the plan gets implemented when needed not that some compliance auditor can verify there is a copy of the plan at the backup and primary control centers. Most entities are going to have their plans at the primary and backup control centers to allow them to implement the plan. If they don't, they likely won't be able to implement their plan in the required time frame. Thus, they will already be violating another requirement so lets not provide an opportunity for double jeopardy.

Requirement 4 should strike "that provides functionality required for maintaining compliance with all Reliability Standards applicable to the Reliability Coordinator". The RC is already required to comply with these standards regardless of whether they operate from the backup center or the primary center.

Requirement 5 should strike "sufficient for maintaining compliance with all Reliability Standards applicable to a Balancing Authority or Transmission Operator respectively". The BA and TOP are already required to comply with these standards regardless of whether they operate from the location of their backup capability or the primary center. Further, we urge the drafting team to consider combining requirements 4 and 5 to require full backup control centers for the TOP and BA as well as the RC. Requirement 5 is already stringent enough that a backup control center is likely required anyway. Combining the requirements just simplifies the standards.

Requirement 6 is really a sub-requirement of requirement 1. Sub-requirement 6.1 is confusing. Because it is a sub-requirement, it must apply to requirement 6. Thus, it would seem that the sub-requirement is requiring the annual review and approval to occur within 60 days of any changes. What if there are multiple changes in the year? From this perspective, it appears that the sub-requirement is intended to reflect that changes can occur at any time. To clarify the requirement, we suggest the following language as a sub-requirement of R1 along with striking requirement 6 and 6.1:"Each RC, BA an TOP shall review and approve its Operating Plan for backup functionality annually and within sixty calendar days of any changes to the backup location, capabilities or contact information, modify the Operating Plan to reflect the changes."

Requirement 7 is unnecessary as an explicit requirement. Each RC, TOP and BA is required to comply with all applicable</td></tr>
</table>

Organization	Question 7:	Question 7 Comments:
		requirements even if they are operating from the location of their backup functionality or backup control center. If their backup functionality relies on the primary control center, the RC, TOP and BA will be unable to comply with numerous other requirements in the event that they lose the functionality of their primary control center. Requirement 8 is not needed and does not accomplish the goal of ensuring the backup capability is available when needed. In reality, an RC, TOP and BA will have to operate utilizing backup functionality significantly more often than annually to ensure that backup functionality is available when needed. In fact, most RC, TOP, and BA already test their backup capability more often than annually even though the current requirement is for an annual test. They do this not because of the testing requirement but because of the need to continue to comply with other applicable requirements. If the other standards requirements already drive the entities to exceed this requirement, why is it needed? It is not. Requirement 9 should be struck. This requirement essentially represents an N-2 condition. The requirements should not try to anticipate extreme conditions such as this. Because RC, TOP and BA are still required to comply with the requirements even if they lose one of the operating centers or backup capability, the RC, TOP and BA will have to make plans to operate in the event of the failure of their last operable control center. Thus, failure to begin developing a plan to replace the backup capability or primary control center will surely result in a violation of another requirement (actually likely many requirements).

Response: Requirement R2 is intended to provide clarity and remove ambiguity as it pertains to the implementation of backup control functionality. R2 will also ensure that the plan will be readily available to assist personnel during an actual event. The SDT believes that the requirement should remain.

R4 & 5: The intent of the drafting team was to provide for the operation of either the primary or backup system individually during periods of emergency, transition, or maintenance without the need for a tertiary backup capability. The SDT has modified Requirements R4 & R5 to provide clarity on this matter.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R4.1 Planned outages of the primary or backup facilities of two weeks or less

R4.2 Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

Organization	Question 7:	Question 7 Comments:
R5.1 Planned outages of the primary or backup functionality of two weeks or less **R5.2** Unplanned outages of the primary or backup functionality R6: Requirement 1 addresses the content of the plan, while Requirement 6 addresses the timeliness of reviews and updates. Therefore, no change was made. R7/R8: Requirements R7 and R8 are intended to provide clarity and remove ambiguity as they pertain to implementation of backup control functionality. The SDT believes that the requirements should remain but has revised Requirement R7 in an attempt to provide additional clarity. **R7.** Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~. R9: The SDT believes that primary or backup functionality should be restored when reasonably practicable after an event. The intent of this requirement is to have a plan within 6 months for major outage situations.		
Northeast Utilities	Yes	
Midwest ISO	Yes	
WECC Reliability Coordinator Comment Working Group	No	
Manitoba Hydro	No	
Oncor Electric Delivery	No	
Santee Cooper	No	

Organization	Question 7:	Question 7 Comments:
Bonneville Power Administration	No	
Dynegy	No	
AEP	No	
Response: Thank you for your response.		

8. Do you believe this standard will help deliver an adequate level of reliability?

Summary Consideration:

Most comments were positive with respect to the standard delivering an adequate level of reliability.

The following requirements were changed due to industry comments in an attempt to provide additional clarity:

R1.6 An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time ~~to~~ to fully implement the backup functionality elements identified in Requirement R1.2~~get backup functionality up and running~~. The Operating Process shall also include:

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during:

R4 VSL

R4	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control

	center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated~~	center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.

R5 VSL

R5	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in

	with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not dated.~~	with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF	with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	accordance with ~~r~~Requirement R5.

Organization	Question 8:	Question 8 Comments:
Consumers Energy Company	No	When drafting standards we should keep in mind the primary goal. That goal is to provide a high level of reliability. There needs to be a balance between the actions of making our operations reliable or taking away from that effort by putting a program in place that majority of effort is administrative, thus detracking from the original goal. Back-up facilities are needed but the amount of data being requested here seems to be excessive burden that changes the focus from preparing for back-up operations to preparing for a NERC audit.
Response: While the BF SDT acknowledges that there are more Measures and Data Retention specified in the new standard EOP-008-1 as compared to the existing standard, we have attempted to craft a standard with the minimum administrative requirements needed to achieve the reliability goals. The Applicability section was written to include only those entities that could have an impact on the BES.”		
Puget Sound	Yes	However, I am concerned that many of the additional requirements of this standard do not add to reliability, just increase

Organization	Question 8:	Question 8 Comments:
Energy		documentation requirements, staffing and costs for a minimal increase in reliability. I am not aware of an instance where an entity has implemented their loss of control center plan and placed the BES in a perilous situation. There are actually few entities large enough to have this affect. I am fully on board with RCs having the capabilities prescribed in this standard, but there are many entities for which this is overkill. Perhaps the standard should place the burden on the RRO or RC to determine adequate levels of backup facilities for the BAs and TOPs under their jurisdiction.
Response: While the BF SDT acknowledges that there are more Measures and Data Retention specified in the new standard EOP-008 as compared to the existing standard we have attempted to craft a standard with a minimum administrative requirement needed to achieve the reliability goals. The Applicability section was written to include only those entities that could have an impact on the BES. After consideration, the SDT determined that providing more latitude for the RE or RC would result in a standard that was too subjective and inconsistent.		
Sierra Pacific Power Co. (dba NV Energy)	Yes	Yes and No. This Standard has some very positive attributes that will help the industry attain an adequate level of reliability. These include the requirement to establish a Plan and Process for transition to the backup center, the definition of transition time from Primary to Backup center and the requirement to conduct an annual test of the functionality. These are necessary elements to ensure reasonable functionality of the backup plan to continue operations. Where it perhaps goes to far is in the areas of requiring auditable records of updates/approvals for minor and insignificant changes to the Plan, and the prescription of the level of redundancy being unclear and perhaps impossible to comply with depending on the assumptions made about the contingency that causes the backup plan to be executed.
Response: The SDT believes that having an up to date Plan is important and that the administrative burden is commensurate with the benefit. The SDT attempted to select language to provide the best balance between clarity and flexibility to match the diverse circumstances of all applicable entities.		
CenterPoint Energy	No	CenterPoint Energy believes this standard will likely deliver a more than adequate level of reliability. Some might argue that more than adequate reliability is always good. However, CenterPoint Energy disagrees with a one-sided view that ignores cost considerations. If more than adequate reliability can be delivered for minimal cost, then such a level of reliability is certainly in the public interest. However, if more than adequate reliability comes at a significant cost, then a balanced view that weighs costs and benefits would better serve the public interest. Specifically, CenterPoint Energy believes R1.3 is unnecessary and could have unintended consequences. R1.2 outlines the requisite backup functionality, rendering R1.3 unnecessary. Given the infrequency with which loss of primary control center functionality occurs (due to the redundancy and hardening of such facilities), it is unnecessary and probably not cost-effective for backup control center functionality to be consistent with the primary control center. Some reduced backup functionality, that still meets the requirements of R1.2, is probably the most cost-effective approach in most circumstances to ensure adequate reliability in the infrequent circumstance of the loss of primary control center functionality. Furthermore, R1.3 could

Organization	Question 8:	Question 8 Comments:
		have the unintended consequence of entities choosing not to voluntarily exceed the minimum required functionality of the primary control center because R1.3 essentially doubles the cost of any discretionary upgrade to the primary control by mandating that the backup facility maintain the same discretionary functionality. Moreover, the primary control center may have functionality unrelated to reliability considerations, such as market-related functionality, that arguably would need to be provided by the backup control center under R1.3. Backup functionality unrelated to reliability considerations should not be mandated by reliability standards but instead should be left to individual entities and their market stakeholders to decide. For all these reasons, CenterPoint Energy believes R1.3 should be deleted. Furthermore, CenterPoint Energy recommends that the SDT consider modifying R4 and R5 to specify that backup functionality be sufficient to comply with all medium or higher VRF requirements. Again, given the infrequency of loss of primary control center events, the most cost-effective approach to ensure an adequate level of reliability for backup control center functionality is probably to not require the lower VRFs to be maintained in such rare circumstances. When considering this recommendation, it might be helpful to remember that control centers operated reliably for years before the version 0 and beyond NERC standards without all the functionality now available and now required by NERC standards. Generally, such reliability was accomplished through more conservative operation. More conservative operation has costs usually in terms of inefficient generation dispatch. However, an entity may find that rare instances of inefficient generation dispatch due to conservative operation by a backup facility might be less costly than the on-going costs to retain full backup capability to meet all the NERC requirements, even the lower VRF requirements.

Response: The BFSDT agrees that there can be significant costs to entities to have a backup control center, however, the standard allows for entities to also contract backup services at another Control Center facility. There will always be challenges for entities to balance costs; however, the BFSDT is of the opinion that it is essential that backup facilities or contracted services be incorporated to ensure reliable operations of the BES. The SDT distinguishes between requiring a backup facility to be "consistent" and requiring it to be a "duplicate".

Requirement R1.3 was intended, for example, to require that the SCADA database at the backup system be routinely updated to match the one at the primary site, so that if you have to operate from the backup system you can still obtain the data you need to operate the system. It does not require that every system present at the primary site also be present at the backup site.

Requirements R4 & R5 and their VSLs have been clarified to address your concern.

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~:

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes

Organization	Question 8:	Question 8 Comments:			
monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively. ~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: **R4 VSL**					
R4	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF. ~~, or the evidence of the demonstration is not~~	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.	

Organization	Question 8:	Question 8 Comments:		
		~~dated~~		
R5 VSL				
R5		The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.~~, or its evidence is not~~	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.

Organization	Question 8:	Question 8 Comments:
		~~dated.~~
Western Area Power Administration	No	Without understanding the implications regarding some of the vague wording on this draft, constructive comments cannot be provided.
Response: Without specific comments, the SDT can not provide specific responses**.** Thank you for your response.		
Brazos Electric Power Cooperative, Inc.	No	We believe this standard to be excessive if the intent is as stated above to have all TO's have a backup control center.
Response: The SDT was careful to refer to backup capability as opposed to backup control center or even backup facility. There is no requirement for a TO to have a backup control center in this standard.		
PJM Interconnection	No	No, not as currently drafted. These comments are extensive, and address nearly every requirement and measure. A thorough re-write of the Standard will be necessary before this can go to ballot.
Response: The SDT has made numerous changes to the standard based on the specific comments received. Please see responses to specific comments in this and other questions.		
AEP	Yes	The two hour requirement (between the loss of primary control center functionality and the time to fully implement the backup plan and get backup functionality up and running) is a more attainable goal. The transition period is addressed in R1.6. With the extended transition period, R1.6 could be expanded to address reliability concerns during the transition.
Response: Requirement R1.6 has been changed in an attempt to provide additional clarity. **R1.6** An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time ~~to~~ to fully implement the backup functionality elements identified in Requirement R1.2~~get backup functionality up and running~~. The Operating Process shall also include:		
Bureau of	No	With regard to the decision not to include Generator Operator (GOP) centrally dispatched control centers we are concerned

<table>
<tr><th>Organization</th><th>Question 8:</th><th>Question 8 Comments:</th></tr>
<tr><td>Reclamation</td><td></td><td>with the introduction of the degree of BES risk to the decision to make a standard applicable to a Reliability Function or to include it in a requirement. This is exemplified in the SDT's statement in their consideration: "The primary issue of whether centrally dispatched generation control centers should be applicable entities to the EOP-008-1 standard is an issue of risk exposure to the reliable operation of the BES." We believe that the usual emphasis is on risk avoidance, and such a change in the basis of what is included or covered by a standard or to whom it applies should be determined by using the NERC ANSI approved Standards process and not a single drafting team.</td></tr>
<tr><td colspan="3"> Response: The SDT sees risk exposure and risk avoidance as two sides of the same coin, i.e., two ways of looking at the same issue. The SDT did not intend, and does not believe, that it did depart from the accepted approach to this type of question. Additionally, the SDT has revised R3 in an attempt to alleviate such concerns. R3. Each <u>Reliability Coordinator, Balancing Authority, and</u> ~~applicable~~ Transmission Operator directing BES operations through other entities shall <u>ensure that backup functionality exists for the BES operations performed through those other entities.</u> ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality~~. The NERC ANSI approved process is that an SDT crafts the initial draft of a standard and then proposes it to the industry in a series of open postings for comments and eventual balloting. </td></tr>
<tr><td>ISO/RTO Council</td><td>No</td><td>We believe that the standard may actually reduce reliability slightly given that the timing requirement for operating utilizing your backup capability has been increased. Given that the need to utilize your backup capability is a rare event, even this reduced level of reliability may be acceptable.</td></tr>
<tr><td colspan="3">Response: Although the amount of time has been increased what must be achieved within the time period has been even more significantly increased. The current EOP-008-0 only requires interim measures to be taken if backup capability will not be in place within an hour; there is theoretically no time limit to implement backup functionality. The SDT wanted to provide a realistic amount of time and place an absolute limit on establishing backup functionality.</td></tr>
<tr><td>FirstEnergy Corp.</td><td>Yes</td><td>Yes - the standard is much improved in defining expectations of implementing back-up capability, testing of the back-up center etc. Although the time allowed to implement backup capability could be perceived to be an increase over the existing EOP-008-1 standard, the existing standard does not include a hard and fast rule on a 1 hour implementation. In EOP-008-1, an entity was permitted to have "interim provisions" without a hard-stop on the time needed to implement the back-up center. In the proposed EOP-008-2 standard, we believe the SDT made the appropriate steps to put a firm time limit for implementation and we feel the 2 hour limit is sufficient. The need to utilize one's backup capability is a rare event and the adjustment made should not adversely effect reliability of the BES.</td></tr>
<tr><td>WECC</td><td>Yes</td><td></td></tr>
</table>

Organization	Question 8:	Question 8 Comments:
Reliability Coordinator Comment Working Group		
San Diego Gas and Electric	Yes	
ComEd / Exelon	Yes	
Entergy System Planning & Operations (Generation & Marketing)	Yes	
Manitoba Hydro	Yes	
San Diego Gas and Electric	Yes	
Progress Energy Carolinas, Inc.	Yes	
NPCC	Yes	Backup functionality for RCs, BAs and applicable TOPs are essential to ensuring continuous reliable operation of the BES. This standard is needed to provide this assurance.

Organization	Question 8:	Question 8 Comments:
Southern Company Transmission	No	Not in its current form. However, with the changes we have recommended, we believe that it could.
Xcel Energy	Yes	There are some areas of concern that need addressed/ clarified. However, if they are properly addressed, then we feel this standard will help deliver an adequate level of reliability.
Duke Energy	Yes	It appears that this standard is moving in the right direction.
MRO NERC Standards Review Subcommittee	Yes	The MRO commends the SDT. The SDT has incorporated many past comments and given great replies to the many questions, Thank you.
ITC	Yes	
Oncor Electric Delivery	Yes	
ISO New England Inc	Yes	Backup functionality for RCs, BAs and applicable TOPs are essential to ensuring continuous reliable operation of the BES. This standard is needed to provide this assurance.
Independent Electricity System Operator	Yes	Backup functionality for RCs, BAs and applicable TOPs is essential to ensuring continuous and reliable operation of the BES. This standard is needed to provide this assurance.
Progress Energy-Florida	Yes	
Pepco Holdings, Inc.	Yes	Operative word is -help- see previous comments

Organization	Question 8:	Question 8 Comments:
- Affiliates		
ReliabilityFirst Corporation	Yes	
Bonneville Power Administration	Yes	
Dynegy	Yes	
Hydro-Québec TransÉnergie (HQT)	Yes	
Santee Cooper	No	We believe with our comments from above included in the standard, that this standard will help deliver an adequate level of reliability.
Ameren	No	With suggested changes.
Response: Thank you for your response.		

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for EOP-008-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

EOP-008-1 — Loss of Control Center Functionality

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards and no new or revised definitions in the proposed standard.

Compliance with Standard

EOP-008-1: Loss of Control Center Functionality	Functions That Must Comply With the Associated Requirements		
	Reliability Coordinator	Balancing Authority	Transmission Operator
R1	X	X	X
R2	X	X	X
R3	X	X	X
R4	X		
R5		X	X
R6	X	X	X
R7	X	X	X
R8	X	X	X
R9	X	X	X

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard.

Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with the requirements.

EOP-008-0 is retired when EOP-008-1 goes into effect.

All requirements of EOP-008-1 will go into effect the first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

116-390 Village Boulevard
Princeton, New Jersey 08540-5721
609.452.8060 | www.nerc.com

Implementation Plan for EOP-008-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this ~~set of~~ standard~~s~~ can be implemented.

EOP-008-1 – Loss of Control Center Functionality

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards and no new or revised definitions in the proposed standard.

Compliance with Standard

EOP-008-1: Loss of Control Center Functionality	Functions That Must Comply With the Associated Requirements		
	Reliability Coordinator	Balancing Authority	~~Applicable~~ Transmission Operator
R1	X	X	X
R2	X	X	X
R3	X	X	X
R4	X		
R5		X	X
R6	X	X	X
R7	X	X	X
R8	X	X	X
R9	X	X	X

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard.

Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with the requirements.

EOP-008-0 is retired when EOP-008-1 goes into effect.

All requirements of EOP-008-1 will go into effect the first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form for the Third Draft of EOP-008-1 — Loss of Control Center Functionality for the Backup Facilities SDT (Project 2006-04)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the 3rd draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **April 15, 2009**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Backup_Facilities.html

Background Information:
The Backup Facilities Standard Drafting Team (BFSDT) has made changes to the third posting of EOP-008-1 — Loss of Control Center Functionality based on comments received from the industry. Major changes included:

- Section 4.1.2 — A revision to the applicability of the Transmission Operator. Now, applicability is to all Transmission Operators.
- Requirement R3 — This now applies to the Reliability Coordinator and Balancing Authority as well as the Transmission Operator.
- Requirements R4 and R5 — Clarifications have been made to the applicability of Reliability Standards, avoiding the need for tertiary functionality, and when backup functionality is not required.
- Requirement R7 — Clarification has been provided with regard to independence of facilities.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this standard. Accordingly, we request that you submit your comments on this form by **April 15, 2009**.

1. The SDT has discovered that Compliance is already enforcing Requirement R3 as part of its review of delegation agreements. Therefore, it appears that this requirement could be deleted. Do you agree that this requirement can be deleted? If not, please provide specific reasons why it shouldn't be deleted.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has made a change in the applicability of the Transmission Operator (see Section 4.1.2) so that all Transmission Operators are treated equally. Do you agree with the change that was made? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

3. The SDT has provided clarifications to the applicability of reliability standards, avoiding the need for tertiary functionality, and when backup functionality is not required in Requirements R4 and R5. Do you agree with these changes? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

4. The SDT has clarified the issue of independence of facilities in Requirement R7. Do you agree with this change? If not, please make specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

5. Do you believe this standard is ready for balloting? If not, please supply the specific reasons for your position.

   ☐ Yes

   ☐ No

   Comments:

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q09. The current draft is the third iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit standard for balloting.	May 2009
2. Submit standard for recirculation balloting.	June 2009
3. Submit standard to BOT.	July 2009
4. Submit to regulatory authorities.	August 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**
2. **Number:** **EOP-008-1**
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.

Effective Date: The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R1.1. The location and method of implementation for providing backup functionality for a prolonged period of time.

R1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

R1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES.

R1.2.2. Data communications.

R1.2.3. Voice communications.

R1.2.4. Power source(s).

R1.2.5. Physical and cyber security.

R1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

R1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

R1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

R1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in Requirement R1.2. The Operating Process shall include at a minimum:

R1.6.1. A list of all entities to notify when there is a change in operating locations.

R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

R1.7. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location supporting backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R4. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R4.1. Planned outages of the primary or backup facilities of two weeks or less

R4.2. Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R5.1. Planned outages of the primary or backup functionality of two weeks or less

R5.2. Unplanned outages of the primary or backup functionality

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R6.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8.1. The transition time between the loss of primary control center functionality and the time to fully implement the backup functionality.

R8.2. The backup functionality for a minimum of two continuous hours.

R9. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide a plan to its Reliability Assurer within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location supporting backup functionality.

M3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator directing BES operations through other entities shall provide evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities, for backup functionality in accordance with Requirement R3.

M4. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R4.

M5. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a backup control center facility or contracted services) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that it's dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities do not depend on each other or any common facility for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R8.

M9. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide evidence that a plan has been submitted to its Reliability Assurer within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the current year and three previous years in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup

functionality, with evidence of its last issue, available at its primary control center and at the location supporting backup functionality, for the current year, in accordance with Measurement M2.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator directing BES operations through other entities shall retain its dated, current, in force Operating Plan for backup functionality, providing evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities for the current year and three previous years, in accordance with Measurement M3.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with requirement R4 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M4.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the current year and three previous years, that it's dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup capabilities do not depend on each other or any common facility for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M8.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months shall retain evidence for the current in force document

and any such documents in force since its last compliance audit that a plan has been submitted to its Reliability Assurer within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Measurement M9.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has a current Operating Plan for backup functionality but the plan is missing one of the sub-requirements or the plan does not reflect the date of its last issuance.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has a current Operating Plan for backup functionality but the plan is missing two of the sub-requirements.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has a current Operating Plan for backup functionality but the plan is missing three or more of the sub-requirements or is not compliant with Requirement R1.5.	The Reliability Coordinator, Balancing Authority, or Transmission Operator does not have a current Operating Plan for backup functionality.
R2.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality available at all of its control locations but at one location it is not the current plan.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality available at all of its control locations but at all locations it is not the current plan.	N/A	The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality but no version of the plan is available at all of its control locations.
R3.	The Reliability Coordinator, Balancing Authority, or Transmission Operator directing BES operations through other entities has not ensured against the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Lower VRF in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or Transmission Operator directing BES operations through other entities has not ensured against the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Medium VRF in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or Transmission Operator directing BES operations through other entities has not ensured against the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a High VRF in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or Transmission Operator directing BES operations through other entities has not ensured against the loss of any such entity's control functionality in its Operating Plan for backup functionality.
R4.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's

R#	Lower	Moderate	High	Severe
	center with certified Reliability Coordinator operators) in accordance with Requirement R4 but it does not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	control center with certified Reliability Coordinator operators) in accordance with Requirement R4 but it does not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	control center with certified Reliability Coordinator operators) in accordance with Requirement R4 but it does not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	control center with certified Reliability Coordinator operators) in accordance with Requirement R4.
R5.	The Balancing Authority or Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with Requirement R5 but it does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Lower VRF.	The Balancing Authority or Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with Requirement R5 but it does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a Medium VRF.	The Balancing Authority or Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with Requirement R5 but it does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality and which have a High VRF.	The Balancing Authority or Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with Requirement R5.
R6.	The Reliability Coordinator, Balancing Authority, or Transmission Operator, has evidence that it's dated, current, in force Operating Plan for	N/A	The Reliability Coordinator, Balancing Authority, or Transmission Operator, has evidence that it's dated, current, in	The Reliability Coordinator, Balancing Authority, or Transmission Operator, does not have evidence that it's dated,

R#	Lower	Moderate	High	Severe
	backup functionality, was reviewed and approved but it was not done in one calendar year or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes to the capabilities described in Requirement R1.		force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in two calendar years or more or that it was updated more than ninety calendar days after any changes to the capabilities described in Requirement R1.	current, in force Operating Plan for backup functionality was reviewed and approved.
R7.	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or Transmission Operator's evidence does not demonstrate that its primary and backup capabilities do not depend on each other or any common facility for the functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality.
R8.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but one of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours. or 3) test results were not documented.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has not annually tested its Operating Plan for backup functionality.

R#	Lower	Moderate	High	Severe
R9.	The Reliability Coordinator, Balancing Authority, or Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months has provided evidence that a plan has been submitted to its Reliability Assurer showing how it will re-establish backup capability but it was submitted in more than six calendar months.	N/A	N/A	The Reliability Coordinator, Balancing Authority, or Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months has not submitted a plan to its Reliability Assurer showing how it will re-establish backup.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q09. The current draft is the third iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit standard for balloting.	May 2009
2. Submit standard for recirculation balloting.	June 2009
3. Submit standard to BOT.	July 2009
4. Submit to regulatory authorities.	August 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator ~~operating Facilities at 200 kV or above, or non-radial Facilities above 100 KV, or Facilities demonstrated by the Regional Entity to be critical to the reliability of the Bulk Electric System (BES)~~.

   4.1.3. Balancing Authority.

Effective Date: ~~As per the Implementation Plan.~~ The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a~~n~~ current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R1.1. The location and method of implementation for providing backup functionality for a prolonged period of time.

R1.2. A~~n~~ ~~overview~~ summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

R1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES.

R1.2.2. Data communications.

R1.2.3. Voice communications.

R1.2.4. Power source(s).

R1.2.5. Physical and cyber security.

R1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

R1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

R1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to ~~plan and get backup functionality up and running that is less than~~ two hours.

R1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time ~~to~~ to fully implement the backup functionality elements identified in Requirement R1.2~~get backup functionality up and running~~. The Operating Process shall include~~:~~ at a minimum:

R1.6.1. A list of all entities to notify when there is a change in operating locations.

R1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary~~/~~ or backup functionality.

R1.7. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a copy of its current Operating Plan for backup functionality ~~located~~ available ~~in~~at its primary control center and at the location supporting backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. ~~include provisions for the loss of such entity's control functionality in its Operating Plan for backup functionality.~~ *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R4. Each Reliability Coordinator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during~~.~~: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R4.1. Planned outages of the primary or backup facilities of two weeks or less

R4.2. Unplanned outages of the primary or backup facilities

R5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall~~, during the time period when the primary control center functionality and the backup functionality are both available for use,~~ have backup functionality (provided either through a backup control center facility or contracted services) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively.~~.~~ To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R5.1. Planned outages of the primary or backup functionality of two weeks or less

R5.2. Unplanned outages of the primary or backup functionality

R6. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R6.1. ~~The~~An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~to the backup location,~~ in capabilities described in Requirement R1~~, or contact information~~.

R7. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have primary and backup capabilit~~y~~ies that do~~es~~ not depend on ~~the primary control center~~ each other or any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality~~.~~. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates ~~includes~~: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R8.1. ~~A demonstration of t~~The transition time between the loss of primary control center functionality and the time to fully implement the backup functionality ~~initiation of backup functionality~~.

R8.2. ~~Actual implementation or test operations of t~~The backup functionality for a minimum of two continuous hours.

~~**R8.3.** Test results shall be documented and lessons learned noted and incorporated in subsequent revisions of the Operating Plan for backup functionality.~~

R9. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator that has experienced a loss of ~~their~~ its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months~~,~~ shall provide a plan to its ~~Regional Entity~~ Reliability Assurer within six calendar months of the date when the functionality is lost, ~~,~~ showing how it will re-establish backup capability. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format. ~~, with evidence of its last issue, describing the manner in which it ensures reliable operations of the BES in the event that its primary control center becomes inoperable.~~

M2. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, ~~with evidence of its last issue, located~~ available ~~in~~at its primary control center and at the location supporting backup functionality.

M3. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall provide evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities ~~included provisions for the loss of such entity's control functionality in its dated, current, in force Operating Plan for backup functionality~~, ~~with evidence of its last issue,~~ for backup functionality in accordance with Requirement R3.

M4. Each Reliability Coordinator shall provide dated evidence ~~that it has demonstrated~~ that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality in accordance with Requirement R4.

M5. Each Balancing Authority and ~~applicable~~ Transmission Operator shall provide dated evidence ~~that it has demonstrated~~ that ~~it's~~its backup functionality (provided either through a backup control center facility or contracted services) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~ that depend on ~~to~~ a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator, shall have evidence that it's dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, ~~with evidence of its last issue,~~ has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the ~~backup location,~~ capabilities described in Requirement R1~~,~~ ~~or contact information~~ in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall have dated evidence that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test~~ed~~ of its ~~dated, current, in force~~ Operating Plan for backup functionality, ~~with evidence of its last issue, and that test results and lessons learned from such testing are noted and incorporated in subsequent revisions of its Operating Plan for backup functionality~~ in accordance with Requirement R8.

M9. Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months~~,~~ shall provide evidence that a plan has been submitted to its ~~Regional~~

~~Entity~~ Reliability Assurer within six calendar months of the date when the functionality is lost~~,~~ showing how it will re-establish backup capability in accordance with Requirement R9.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the current year and three previous years in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, ~~located in~~available at its primary control center and at the location supporting backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator directing BES operations through other entities shall retain its dated, current, in force Operating Plan for backup functionality, ~~with evidence of its last issue,~~ providing evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities ~~included provisions for the loss of such entity's control functionality~~ for the current year and three previous years, in accordance with Measurement M3.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at

another entity's control center with certified Reliability Coordinator operators) in accordance with requirement R4 that provides the functionality required for maintaining compliance with all Reliability Standards ~~applicable to the Reliability Coordinator~~ that depend on primary control center functionality in accordance with Measurement M4.

- Each Balancing Authority and ~~applicable~~ Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a backup control center facility or contracted services) in accordance with requirement R5 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~applicable~~that depend on ~~to~~ a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M5.

- Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator, shall retain evidence for the current year and three previous years, that it's dated, current, in force Operating Plan for backup functionality, ~~with evidence of its last issue,~~ has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the ~~backup location,~~ capabilities described in Requirement R1~~, or contact information~~ in accordance with Measurement M6.

- Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality in accordance with Measurement M7.

- Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its ~~dated, current, in force~~ Operating Plan for backup functionality, ~~with evidence of its last issue,~~ in accordance with Measurement M8.

- Each Reliability Coordinator, Balancing Authority, and ~~applicable~~ Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months~~,~~ shall retain evidence for the current in force document and any such documents in force since its last compliance audit~~,~~ that a plan has been submitted to its ~~Regional Entity~~ Reliability Assurer within six calendar months of the date when the functionality is lost~~,~~ showing how it will re-establish backup capability in accordance with Measurement M9.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing one of the sub-requirements or the plan ~~is~~ does not ~~dated with evidence~~reflect the date of its last ~~issue~~issuance.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing two of the sub-requirements.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has a~~n~~ current Operating Plan for backup functionality but the plan is missing three or more of the sub-requirements or is not compliant with Requirement R1.5.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator does not have a~~n~~ current Operating Plan for backup functionality.
R2.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality ~~but the plan is not located~~ available ~~in~~ at ~~one~~all of its control locations but at one location it is not the current plan.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has an Operating Plan for backup functionality ~~but the plan is not located~~ available ~~in~~at ~~either~~ all of its control locations but at all locations it is not the current plan.	N/A	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality but no version of the plan is available at all of its control locations.
R3.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Lower VRF ~~for 10% or less of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Medium VRF ~~for more than 10% and less than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a High VRF~~for more than 25% of its applicable entities~~ in its Operating Plan for backup functionality.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator directing BES operations through other entities has not ensured against ~~included provisions for~~ the loss of any such entity's control functionality in its Operating Plan for backup functionality.

R#	Lower	Moderate	High	Severe
R4.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.~~, or the evidence of the demonstration is not dated.~~	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4 but it ~~only provides~~does not provide the functionality required for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator has not demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R4.
R5.	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~90%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control center functionality	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~80%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control	The Balancing Authority or ~~applicable~~ Transmission Operator has demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5 but it ~~only includes~~does not include monitoring, control, logging, and alarming sufficient for maintaining compliance with ~~70%~~one or more of the Requirements in the Reliability Standards applicable to a Balancing Authority and Transmission Operator respectively that depend on the primary control	The Balancing Authority or ~~applicable~~ Transmission Operator has not demonstrated that it has backup functionality (provided either through a backup control center facility or contracted services) in accordance with ~~r~~Requirement R5.

R#	Lower	Moderate	High	Severe
	and which have a Lower VRF.~~, or its evidence is not dated.~~	center functionality and which have a Medium VRF.	center functionality and which have a High VRF.	
R6.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, ~~with evidence of its last issue,~~ was reviewed and approved but it was not done in one calendar year ~~more than twelve calendar months and less than or equal to fifteen calendar months~~ or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes to the ~~backup location,~~ capabilities described in Requirement R1~~, or contact information~~.	~~The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was done in more than fifteen calendar months or that it was updated more than ninety calendar days after any changes to the backup location, capabilities, or contact information.~~ N/A	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in two calendar years or more or that it was updated more than ninety calendar days after any changes to the capabilities described in Requirement R1.	~~N/A~~ The Reliability Coordinator, Balancing Authority, or Transmission Operator, does not have evidence that it's dated, current, in force Operating Plan for backup functionality was reviewed and approved.
R7.	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator's ~~dated~~ evidence does not demonstrate~~shows~~ that its primary and backup capabilit~~y~~ies do~~es~~ not depend on each other or any common facility ~~the primary control center~~ for the functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality.

R#	Lower	Moderate	High	Severe
R8.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator ~~has provided evidence, such as dated records, that it~~ has annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality, but one of the following occurred: 1) the demonstration was ~~with evidence of its last issue, through actual implementation or test operations~~ for less than two continuous hours, 2)~~or~~ it has failed to demonstrate that the transition time period is less than or equal to two hours~~,~~. ~~or it was done in more than twelve calendar months~~ or ~~3~~ 3) test results ~~and lessons learned~~ were not ~~incorporated~~ documented~~in subsequent revisions of the Operating Plan for backup functionality~~.	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but two of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented. ~~N/A~~	The Reliability Coordinator, Balancing Authority, or Transmission Operator has annually tested its Operating Plan for backup functionality, but all three of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it has failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented. ~~N/A~~	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator has not annually tested its ~~dated, current, in force~~ Operating Plan for backup functionality.
R9.	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months~~,~~ has provided evidence that a plan has been submitted to its ~~Regional Entity~~ Reliability Assurer showing how it will re-establish backup capability but	N/A	N/A	The Reliability Coordinator, Balancing Authority, or ~~applicable~~ Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months~~,~~ has not submitted a plan to its ~~Regional Entity~~ Reliability Assurer showing how it will re-establish backup.

R#	Lower	Moderate	High	Severe
	it was submitted in more than six calendar months.			

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
March 17–April 15, 2009

Now available at: http://www.nerc.com/filez/standards/Backup_Facilities.html

Third Draft of EOP-008-1 — Loss of Control Center Functionality (Project 2006-04 — Backup Facilities)

The Backup Facilities Standard Drafting Team (Project 2006-04) has posted its third draft of EOP-008-1 — Loss of Control Center Functionality for a 30-day comment period **until 8 p.m. EDT on April 15, 2009**. A revised implementation plan and the team's consideration of industry comments on the second draft of the standard have also been posted.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-452-8060. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Backup_Facilities.html

Project Background

The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable.

The third posting of EOP-008-1 includes changes based on comments received from the industry. Major changes included:

- Section 4.1.2 — A revision to the applicability of the Transmission Operator. Now, applicability is to all Transmission Operators.
- Requirement R3 — This now applies to the Reliability Coordinator and Balancing Authority as well as the Transmission Operator.
- Requirements R4 and R5 — Clarifications have been made to the applicability of Reliability Standards, avoiding the need for tertiary functionality, and when backup functionality is not required.
- Requirement R7 — Clarification has been provided with regard to independence of facilities.

Further background information is available on the project page:
http://www.nerc.com/filez/standards/Backup_Facilities.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (35 Responses)
Name (22 Responses)
Organization (22 Responses)
Group Name (13 Responses)
Lead Contact (13 Responses)
Contact Organization (13 Responses)
Question 1 (35 Responses)
Question 1 Comments (35 Responses)
Question 2 (35 Responses)
Question 2 Comments (35 Responses)
Question 3 (35 Responses)
Question 3 Comments (35 Responses)
Question 4 (35 Responses)
Question 4 Comments (35 Responses)
Question 5 (35 Responses)
Question 5 Comments (35 Responses)

-
Individual
John Tolo
Tucson Electric Power
Yes
I agree R3 should be deleted
Yes
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
Yes
Yes
No
We agree with the approach. We recommend that the term "data center" be defined. How will the independence of any single data center be evaluated? This is almost impossible to prove. What type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.
No
Once "data center" is clearly defined, we believe the standard will be ready for balloting. For lack of a general comments question, would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be used consistently throughout the Standards.
Individual
Dan Rochester

Ontario IESO
Yes
Yes, this requirement should be removed – but not for the reason stated above. If there is no R3, there is no requirement that Compliance would be able to enforce in the first place. However, we believe that R3 can be removed if R1 is modified as follows (suggested deletion in parenthesis): "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control functionality is lost. (center becomes inoperable.) This Operating Plan for backup functionality shall include the following, at a minimum:"
Yes
A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration.
Yes
We agree with the clarification language that is added to avoid the need for tertiary functionality. However, we wonder why R4 stipulates specifically the requirement for a "backup control centre facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators" as opposed to adopting the more appropriate language used in R5, viz. "backup functionality (provided either through a backup control center facility or contracted services)". It is conceivable that an RC may arrange for backup capability with another entity as opposed to having its own backup facility. Also, it has been raised by many commenters in previous postings that it is the backup "capability" or "functionality" that matters, not the facility. We suggest R4 be revised to adopt this more flexible and appropraite language. If the different language in R4 was intended to also stipulate the need for having certified RC operators, then why is this not a requirement in R5? The two requirements should have similar if not identical language. We also think that the last part of both requirements that says: "…compliance with all Reliability Standards that depend on a primary control center functionality" is unnecessary. The responsible entity must comply with all reliability standards under either the primary functionality or backup capability condition. Isn't meeting all reliability standards and continuing to operating, monitor and maintain BES reliability the very reason for having the backup functionality?
Yes
We agree with the clarifying language, but hold the opinion that the last part of the requirement "that depend on the primary control functionality" is unnecessary. The responsible entity must comply with all reliability standards under either the primary functionality or backup capability condition, hence the need for the backup functionality.
No
Whether or not the standard is ready for ballot will depend on the extent to which the above comments are addressed. Further, the following comments also need to be addressed: VSLs for R2: The Severe condition is "The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality but no version of the plan is available at all of its control locations." There is no mention of having no version at one of the primary and backup control locations. If one version is missing, what VSL is assigned? VSLs for R3: VSL measures the extent to which an entity fails a requirement, not how impactive the failure is. However, the VSLs for R3 are assigned according to what level of VRFs the requirements have failed. Factoring the impact of a failure in the determination of the extent of failure is improper. These need to be revised. VSLs for R4: Similar comments as for VSLs for R3. Further, please note our comments and suggestions under Q3. If R4 is to be revised, the VSLs (and Measure) will need to be revised accordingly. VSLs for R5: Same comments as for VSLs for R4. We are particularly concerned with the determination of VSL based on VRFs for R3, R4 and R5. This is improper in applying the fundamental concept of VRF and VSL. We feel that the standard is not ready for balloting until these VSLs are revised to remove the VRF component.
Group
PJM Interconnection
Patrick Brown
NERC & Regional Coordination Department
Yes
We agree that Requirement R3 should be deleted. Backup capability is defined as "the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational" as such, "backup capability" does not need to equate to "backup facility." The standard should be written to require the necessary/essential functionality (not require another facility) when the primary capability is lost (as is done in R1). Simply, the standard needs to require the principle need, yet not be too prescriptive on how that is accomplished.
Yes
Yes
We agree that the clarifications provided are correct and that there is no need for 'tertiary functionality.' However, it appears some clarifying language is needed to better articulate the need for "backup capability." In addition, while the language in R4 is fairly clear, the language in R5 is very confusing and has the affect of including multiple requirements

in one run on sentence. This will pose problems both in terms of trying to adhere to the requirement as well as trying to audit the requirement. Although it appears the SDT was looking to include acceptable risk for time periods of two weeks or less for planned outages when backup functionality is not required, we do not believe that there should be any reference to 'tertiary facility' or 'backup facility' in this requirement with respect to planned or unplanned outages. As such, we believe these sub requirements can be omitted. We propose the following language to the SDT for Requirements 4 and 5 with the caveat that the SDT must resolve the frequency for which it is acceptable to not have backup capability (it shoud be a risk-informed basis): R4. Each Reliability Coordinator shall have backup capability (provided either through a backup control center or through contracted services or other pre-established means) utilizing certified Reliability Coordinator operators and the functionality necessary to maintain compliance with all reliability standards and the situational awareness provided by the primary control center when it is operational. The unavailability of backup capability is permissable for periods of up to two weeks per _________ due to planned or unplanned outages as long as the Responsible Entity implements continuing and reasonable efforts to restore its backup capability. R.5. Each Balancing Authority and Transmission Operator shall have backup capability (provided either through a backup control center or through contracted services or other pre-established means) that includes monitoring, control, logging, and alarming functionality necessary to maintain compliance with all reliability standards and the situational awareness provided by the primary control center when it is operational. The unavailability of backup capability is permissable for periods of up to two weeks per _________ due to planned or unplanned outages as long as the Responsible Entity implements continuing and reasonable efforts to restore its backup capability.
Yes
No
Numerous requirements need to be rewritten for clarification and subsequently, VSLs will need to be rewritten followed by another posting prior to this standard being ready for balloting. In addition, there are still some areas which should be cleaned up: R1 - the term current should be ommitted as it adds a new term which should simply be covered by R6. R1.2.5 - does this refer to CIP 003 - CIP 009, or some other cyber security requirements?
Individual
Jack Kerr
Dominion Virginia Power
No
If there is a reliability need for backup capabilities for delegated tasks, then this should be explicitly stated in a reliability standard. It should not be implied or be something that. on review, Compliance deems is necessary but that is without a clear basis in the standards.
Yes
No
As written, the clarifications do not appear to have avoided the need for tertiary facilities/functionalities. In fact, the proposed wording implies that there is a need for tertiary facilities/functionalities if a planned outage of more than two weeks is anticipated. An RC or TOP is not likely to assume that some day they might have to plan an outage in excess of two weeks and then go ahead and acquire tertiary facilities/functionalities to have on hand just in case. Therefore, it should be clear that, under normal operations (all systems "Go"), only primary and adequate backup facilities/functionalities are required for compliance. Failure to provide adequate backup in the first place would constitute non-compliance. Under degraded operations (loss of primary facilities/functionalities or loss of the adequate backup facilities/functionalities previously provided), there should be separate and specific requirements for plans an RC or TOP should make and/or actions they should take until normal operations are restored (similar to what R1.6.2 now says but promoted to a stand-alone requirement). Compliance under degraded operations would be evaluated based on these new requirements specific to degraded operations instead of the original requirements to have backup facilities/functionalities. This eliminates the conundrum of being non-compliant when primary or backup facilities/functionalites are lost. Tertiary facilities/functionalities are not cost effective and are not necessary to achieve an Adequate Level of Reliability. Some entities, especially those who operate markets, may chose to acquire tertiary facilities/functionalities for various reasons. In doing so, they are choosing to "plan and operate their portion of the System to achieve a level of reliability that is above the standards." (Words in quotes are from the NERC definition of Adequate Level of Reliability.)
Yes
The SDT should be aware of the concerns about NERCnet and the ISN that have been discussed by the Reliability Coordinator Working Group. If the loss of "any single data center" at a service provider facility can result in the ISN data being unavailable, is this a potential compliance issue? The measure M7 refers to "any common facility" instead of to "any single data center". The requirement and the measure should use the same terms.
No
1) See response to question 3. 2) Requirement R9 allows 6 months after an unplanned outage before a plan is needed for restoration of the primary or backup capability. This is too long. A plan should be required within two weeks even if it is only a preliminary plan. The plan should be updated at least monthly thereafter until the restoration is complete.

Individual
Al McMeekin
South Carolina Electric & Gas Company
Yes
Yes
No
Suggested language for R4: Each Reliability Coordinator shall have backup control center functionality provided through its own dedicated backup facility or at another entity’s control center with certified Reliability Coordinator operators for maintaining compliance with all applicable Reliability Standards. No tertiary functionality is required. Suggested language for R5: Each Balancing Authority and Transmission Operator shall have backup functionality provided through a backup control center facility or contractual services, for maintaining compliance with all applicable Reliability Standards. No tertiary functionality is required.
No
See my suggested version of the standard.
No
See my suggested version of standard. R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of their most recently approved Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its control center becomes inoperable. This Operating Plan for backup functionality shall be available in its primary control center and at the location supporting backup functionality. The Operating Plan shall include the following: R1.1. Operating Procedures that stipulate: R1.1.1 Who has the decision-making authority for determining when to implement the Operating Plan. R1.1.2 The actions required to transition from loss of primary control center functionality to backup control functionality. R1.1.3 The actions required during the transition period. R1.1.4 The estimated transition time to fully implement the backup functionality which must be attained in less than or equal to two hours. R1.1.5 The list of all entities to notify when a change of operating locations or functionality is required. R1.1.6 The roles for personnel involved during the initiation and implementation of the Operating Plan. R1.2. A summary description of the elements required to support the backup functionality. These elements shall include: R1.2.1. Tools and applications that allow visualization capabilities to ensure operating personnel maintain situational awareness of the BES. R1.2.2. Data communications. R1.2.3. Voice communications. R1.2.4. Power source(s). R1.2.5. Physical and cyber security. R1.3. A description of the methods used for keeping the backup functionality compatible with the primary control center functionality. R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall annually review and approve its Operating Plan for backup functionality R2.1. An Operating Plan shall be updated and approved within sixty calendar days of any changes described in Requirement R1. R3 (Deleted) R4. See Question 3. R5. See Question 3. R6. (Now R2) R7. Incorporated into R1. R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan once each calendar year and document the results. The results should state: R8.1 The transition time from loss of primary control center functionality to full backup control functionality. R8.2 The length of time the backup functionality was utilized to operate the BES. A minimum of two continuous hours is required. R9. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability, and anticipates that loss will last for more than six calendar months shall provide a plan to its Reliability Assurer within six calendar months of the date the functionality was lost, detailing how it will re-establish backup capability.
Individual
Randy Schimka
San Diego Gas and Electric Co
Yes
Yes
Yes
No
We agree with the change in principle, but there is different language in requirement R7 vs. the measure M7. The requirement states "Each other or any single data center" and the measure states "Each other or any common facility", which has a different meaning to us. Our preference would be for both sentences to use the "common facility" language.
No
We have a few issues related to the language in the revised standard that we feel need to be addressed: R1.1 - the

phrase "prolonged period of time" needs to be defined more clearly. One person could interpret that phrase to mean 3 months, while another person might think anything over 1 week is prolonged. R3 - "Transmission Operator directing BES operations through other entities"...We would suggest replacing the word "entities" with something else, such as parties or organizations. We feel that "entities" is too closely related to the registration process. What if the party in question is not a registered entity? It gets confusing. R6.1 - We would suggest adding the word "substantial" so that the second line reads "shall take place within sixty calendar days of any substantial changes". Other wording that is more precise is also welcome, but we wanted it to be clear that an update of the plan is not necessary for more trivial changes that happen several times per month at the control centers. R9 - We don't understand who the "Reliability Assurer" is. We actually liked the previous "Regional Entity" wording. Thanks very much, Randy Schimka SDG&E
Individual
Thomas Fung
BCTC
Yes
Yes
Yes
Yes
Yes
Individual
Chris Scanlon
Exelon
Yes
Yes
No
We agree with the intent of the changes and support the need to avoid creating a requirement for a tertiary control center. However, we believe the changes are confusing and there is large amount of extraneous information that only confuses the mater. For instance, there is no need to state "that provides the functionality required for maintaining compliance with all Reliabilty Standards". RCs are already to comply with all applicable standards regardless of this statement and whether they are operating from their primary or backup facility. This clause does nothing to increase or strengthen that requirement and is unneeded. We suggest modifying R4 to: "Each RC shall have a backup control center facility available except: during planned outages of the primary or backup facilities of two weeks or less or during uplanned outages of the primary or backup facilities." Likewise, we suggest the following wording for R5: "Each BA and TOP shall have backup functionality that includes monitoring, control, logging, and alarming available execpt: during planned outages of the primary or backup facilities of two weeks or less or during uplanned outages of the primary or backup facilities."
No
We agree with what we believe is the drafting team's intent. However, the current wording is ambiguous and is subject to inconsistent interpretation and application. Therefore the suggest the wording for R7 being changed to: Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and back-up facilities that can independently maintain the functionality, data availability and communications needed to maintain compliance with Reliability Standards.
No
There are significant opportunities for rewording requiremnts in this revision, for example the ambiguous wording in R7 requires a fourth comment period.
Individual
Alice Murdock
Xcel Energy
No
If something is monitored by Compliance, then there needs to be an associated standard/requirement. In this case, what standard or requirement would apply if this were to be deleted?
Yes

Yes
Recommend R5.2 include a time limit (e.g. 14 days) as well; may need to add a cumulative limit per year on both as well to prevent abuse. Enhance the allowable planned outage time as a reference to days (e.g. 14 days), rather than weeks, for more clarity.
Yes
However, this seems misplaced. possibly move in R1?
No
We agree with the intent of the standards but would like the items mentioned in our comments addressed prior to balloting. R1.1 "prolonged" is a subjective term and will need to be changed or defined in order to have a standard that minimizes interpretation. R1.3 "consistent" is a subjective term and will need to be changed or defined in order to have a standard that minimizes interpretation.
Group
Ameren Services
Gerry Beckerle
Ameren Services
Yes
Yes
No
R4 and R5 should be combined and all three entities, RC, BA, and TOP should be required to have at least two facilities that are independent of each other to the extent that compliance to NERC Standards can be maintained from those facilities. These facilities maybe a primary facility, with backup(s), or multiple primary facilties. Facilities may be shared with other entities, but must be able to meet the compliance requirements of all the entities sharing the facility. If an entitiy has two independent facilities that they can operate from, whether shared or not, a tertiary is not required. If for any reason an entity does not have at least two facilities to operate independantly from, that entity must prepare a mitigation plan acceptable to their Regional Entity.
No
R7 is redundant of R1 and should be removed. If a facility becomes "inoperable", and the entitity has another facility capable of operating and meeting the NERC compliance standards, then it would be independent.
No
R1: Delete the word "current", it is not defined and adds nothing. R1: "backup functionality" should be restored to "backup capability" R1.1: "functionality" should be replaced with "facility" and "for a prolonged period of time" defined. This may be the period of time it would take to completely replace the facility that became inoperable. R3: Agree that it should be removed as mentioned in Question 1, above. R4 and R5:In addition to the consideration of the comments in question 3, above; R4 should be clear that an RC's backup control center, that happens to be another entity's control center, does not depend on their primary control center. Likewise R5 should be clear that an BA/TOP backup control center, that happens to be provided through contracted services, does not depent on their primary control center R4.1, R4.2, R5.1, and R5.2 are exceptions and if they remain should be clearly stated as such. No subrequirements should be worded, such that on their own they could be mis-interpeted. R6.1 Only changes pertinent to the implementation of the operating plan should be required within the time frame specified. R7: As noted above in question # 4, R7 is redundant of R1 and should be removed. If a facility becomes "inoperable", and the entitity has another facility capable of operating and meeting the NERC compliance standards, then it would be independent. R8: Define "annual"; is it a calander year or something else. Under the effective date section of this standard, clearly state when the first test needs to be completed. R8.1 Add "simulated" in front of "loss of primary control" M1: Is there a significance in the words "current, in force Operating Plan"? Is not "current" and "in force" the same? If not, please explain. M2: Is there a significance in the words "current, in force Operating Plan"? Is not "current" and "in force" the same? If not, please explain. M6: Is there a significance in the words "current, in force Operating Plan"? Is not "current" and "in force" the same? If not, please explain.
Individual
Brent Ingebrigtson
E.ON U.S.
Yes
Yes
No

R5 - The first sentence is long and redundant. Compliance is required whether operating from the primary facility or backup facility. The sentence could end after "…maintaining compliance". Also, R5.1 and 5.2 should not be sub-requirements but rather bullets. Finally, the standard should explicitly state that tertiary functionality is not required.
No
R7 - Rather than a spearate requirement R. 7, the drafting team should consider adding language to R1 that specifies required redundancy.
No
R1.6.2 appears redundant with R1.6 which requires a description of the actions to be taken during the transition. The phrase "manage the risk" is vague and subject to differing interpretations by organizations and auditors. R1.6.2 also describes outages of primary or backup functionality which can be different from a "loss of primary control center" used in R1.6. Requirement R. 8 requires "an annual test of its Operating Plan that demonstrates: the transition time…". R8 introduces additional reliability risk for the BES by requiring RC/BA/TOPs to annually remove from service their primary control center, relocate staff, and then re-intialize all systems. This standard should allow for simulated exercises rather than actual test, similar to requirements in EOP-005. Annual test should be defined as a test each "calendar year".
Group
Pepco Holdings, Inc - Affiliates
Richard Kafka
Pepco Holdings, Inc.
Yes
Yes
Yes
Yes
Yes
Group
Southern Company Transmission
JT Wood
Southern Company Services, Inc.
Yes
Yes
No
We suggest combining R4 and R5 into one requirement and indicating that a tertiary functionality is not required for the functional entities listed. If a tertiary functionality is required, conditions for when it is required should be addressed rather than stating when it is not required. We have additional suggested revisions to R4 and R5, which are included in the comments for Question 5.
No
The language should be more specific in indicating that an event that could make the primary center inoperable should not make the backup functionality inoperable. We suggest adding language in R1 that addresses mitigation of single points of failure and, therefore, eliminate R7.
No
We have the following comments regarding the noted requirements of this standard: R1: The word, “current”, should be removed from the language of the requirement. R1: What is the difference between “operability” “and functionality”? Are they the same? R1.1: Delete "for a prolonged period of time." R1.3: What does “consistent” mean? – does it mean "adequate to meet compliance"? 1.6.2: This requirement appears to be redundsant to R1.6. R2: The word, “current”, should be removed from the language of the requirement. R4: In the first sentence, change "facility" to "functionality" and delete all remaining language of the sentence following "functionality. R5: In the first sentence, delete all remaining language of the sentence following "functionality". R6.1: We suggest that changes that are necessary for the operator to implement the back-up plan should be updated within 60 days - all other changes shall be addressed during the annual review. R8: When does the first test have to be performed, following implementation, to be compliant? - one day or within one year after implementation? We request that "annual" be replaced with "a calendar year". R8.1: We suggest adding the word "simulated' in front of "loss of primary control". General Comment: Measures and VSLs should use the same words and be consistent with the requirements of the Standard.

Individual
Darryl Curtis
Oncor Electric Delivery
No
This requirement shoud stay in EOP-008-1 because the "other entities" referred to in R3 are the entities that have actual device control of BES elements (very true in ERCOT).
Yes
Yes
Yes
Yes
Group
Bonneville Power Administration
Denise Koehn
Transmission Reliability Program
Yes
Yes
Not sure if it should be applicable to small TOPs.
No
If we have a planned outage for 3 weeks (longer than 2 weeks criteria) of either the primary or the backup facility we need a alternate (tertiary facility under the new requirements) facility in place. Current standard says we need interim provisions during transfer if it will take longer than 1 hour to implement plan. New standard has a 2 hour window requirement for the plan to be fully implemented.
Yes
May be OK: Uncertainty due to the phrase "or any single data center". Not sure what that means. In data retention and VSL sections it refers to it as a common FACILITY.
No
It has potential, but not sure about possible planned construction outage time duration.
Group
PacifiCorp
Sandra Shaffer
PacifiCorp
No
Requirement 3 should be left in the Standard. While it may be redundant with present efforts to review delegation agreements, it stipulates the intent of the Standard: that entities remain responsible for operations on the BES even if those duties are implemented via others. Keeping this requirement in the Standard, explicitly, insures that all entities understand the requirements and intent of this Standard, regardless of changes that may occur in the future regarding a separate process associated with review of delegation agreements. The process to review delegation agreements can change without industry input, as that process is not subject to the same approval requirements as those necessary when a Standard is created or modified.
Yes
Yes
Yes
No
R9 is ambiguous and requires clarification prior to balloting. It is unclear whether R9 requires that the responsible entity must submit a plan within six months showing how it will re-establish backup capability or whether it requires the responsible entity to completely re-establish backup capability within six months. This is a very critical distinction. In addition, R9 contains the term "Reliability Assurer" which is not a NERC defined term. It is unclear to what entity this term is referring. This must be clarified before the Standard is ready for balloting.

Individual
Thad Ness
American Electric Power (AEP)
Yes
No
t seems that 200 kV provides a reasonable demarcation of transmission facilities on the Bulk Electric System; below 200 kV are generally more localized distribution facilities. Within this segment, the existing applicability treated all Transmission Owners equally.
Yes
Yes
Yes
While ready for ballot, a couple other suggestions: (a) The term "Reliability Assurer" should be defined within the appliability of the standard. Is it typically the RC, NERC, or some other entity? (b) R9 - What is the action that the Reliability Assurer to take when it receives the plan. If no action is required, the plan could be maintained by the RC, BA, or TO. We are not sure of what value is intended to be provided by the Reliability Assurer when the plan is received perhaps months after the loss of primary and/or back-up capability. (c) R3, M3 - We are not sure that references to third party entities is necessary as the applicable entity is ultimately still responsible.
Group
FMPA and its ARP Participants Listed as Follows: City of Vero Beach; Kissimmee Utility Authority; and Beaches Energy Services
Frank Gaffney, Regulatory Compliance Officer
Florida Municipal Power Agency; City of Vero Beach; Kissimmee Utility Authority; Beaches Energy Services
Yes
No
We agree that all Transmission Operators should have a plan for loss of control center functionality, but, as written, the standard, particularly Requirement 5, seems to force all BAs and TOPs to have a back-up control center or contract for services for one (see paranthetical in R5 and M5). We believe that smaller BAs and TOPs can meet all of the requirements within the standard for backup functionality without a back-up control center or contracted services. For instance, we know of at least one TOP that is only a TOP for one substation, and therefore existing substation facilities can fulfill all of the backup functionality specified in the standard without the need for a backup control center. Similarly, we know of at least one BA who only has one power plant in its BA area, meaning that the BA can be operated from the power plant without a backup control center. We suggest striking the paranthetical in R5 and M5, or expanding it to read "provided either through a backup control center facility, contracted services, or other means".
Yes
No
As written, the requirement R7 (and M7) could be interpreted as requiring redundant Remote Terminal Units (RTUs) at substations and associated communcations. The wording of the requirement should be made to define more accurately what primary and backup capabilities are, and that they do not include the RTUs or communication from the RTUs.
No
See comments above. We suggest: 1) removing the paranthetical from R5 and M5; 2) defining what "primary and backup capabilities" in R7 and M7 mean more specifically, and specifically excluding the need for redundant RTUs and associated communications; 3) Reliability Assurers (referred to in R9 and M9) ought to be a defined term, or we suggest staying with Regional Entity at this time until Reliability Assurers is a defined term in NERC's Glossary; and 4) although R1.2 only refers to physical and cyber security and does not refer to "Critical Assets" or "Critical Cyber Assets", it ought to be clear that just because there may be a backup control center, it does not automatically become a Critical Asset or Critical Cyber Asset, especially if the primary control center is not a Critical Asset or Critical Cyber Asset
Individual
D. Bryan Guy
Progress Energy
Yes
Yes

No
We suggest combining R4 and R5 into one requirement.
Yes
No
Effective Date: Include when the first test of the Operating Plan (R8) has to be performed. Is it (a) before the effective date, (b) within the same calendar year as the effective date, or (c) within 1 year of the effective date? To be consistent with the once per calendar year recurring requirement, we suggest option (b). R1.3: The term “consistent” can have too many interpretations - it could be interpreted that the backup tools must be exactly the same as the primary, which should not be required. If this statement was intended as a reminder to keep Operator tools similar at the backup, then make this a "should" statement instead of a "shall." Another option would be to reword it to say "for keeping the backup functionality adequate to meet compliance." R8: Suggest clarifying "annual" here and in all other applicable sections of the standard. Based upon the SDT's response to previous comments, we recommend using the phrase "once per calendar year"
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
Yes
Yes
Yes
No
We agree with the approach. We recommend that the term "data center" be defined. How will the independence of any single data center be evaluated? This is almost impossible to prove. What type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.
No
Once "data center" is clearly defined, we believe the standard will be ready for balloting. For lack of a general comments question, we would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be be consistently used throughout the Standards.
Individual
Rao Somayajula
ReliabilityFirst Corporation
Yes
Yes
Yes
Yes
Yes
Individual
Edward J Davis
Entergy Services, Inc
Yes
Yes

Yes
Yes
Yes
We request the drafting team consider increasing the maximum transition time to 3 hours from 2 hour in R1.5. The cost of full implementation of backup functionality in 2 hours is significantly greater than implementation within 3 hours with little attendant increase of reliability resulting from the additional one hour.
Group
Midwest ISO Standards Collaborators
Jason L. Marshall
Midwest ISO
Yes
Yes
No
We agree with the intent of the changes and support the need to avoid creating a requirement for a tertiary control center. However, we believe the changes are confusing and there is large amount of extraneous information that only confuses the mater. For instance, there is no need to state "that provides the functionality required for maintaining compliance with all Reliabilty Standards". RCs are already required to comply with all applicable standards regardless of this statement and whether they are operating from their primary or backup facility. This clause does nothing to increase or strengthen those requirements and is unneeded. We suggest modifying R4 to: "Each RC shall have a backup control center facility available except: during planned outages of the primary or backup facilities of two weeks or less or during uplanned outages of the primary or backup facilities." Likewise, we suggest the following wording for R5: "Each BA and TOP shall have backup functionality that includes monitoring, control, logging, and alarming available execpt: during planned outages of the primary or backup facilities of two weeks or less or during uplanned outages of the primary or backup facilities."
No
We agree with the drafting team's intent. However, we believe this requirement should be a sub-requirement of R1. Also, the VSL associated with Requirement 7 violates the Commission established VSL guideline that a VSL can't add to the requirement. Instead of using the data center as the requirement does, the VSL uses common facility. Facility could be construed to mean any communication equipment outside of the control centers and data center and ultimately out of the control of the registered entity if they rely on third party communications.
No
There is significant clean up identified in this standard. A fourth comment period should be pursued to verify that the drafting team has addressed concerns appropriately. Additionally, we offer these comments. We suggest it is possible to create four VSLs for requirement 9 based on the number of months the plan is late. FERC established in their June 2008 VSL order that their preference is to create a VSL for every level if possible. This is clearly possible based on our suggestion.
Group
FirstEnergy
Sam Ciccone
FirstEnergy Corp.
Yes
We agree that the compliance concept of delegation agreements should not reside in this or any reliability standard. The rules governing delegation of tasks should be clearly described in the NERC Rules of Procedure or Registration Criteria.
Yes
Yes
However, the change to R4 that requires "certified Reliability Coordinator Operators" should be carried through to R5 to require BAs and TOPs delegate tasks to NERC certified BAs and TOPs. This will make R4 and R5 consistent.
Yes
Although we agree with R7, it should be clear that this requirement cannot be met during the time period when the primary or back-up functionality is lost for more than six months as provided by R9. We ask that this be clarified by adding the wording "except as permitted by R9" at the end of Requirement R7. Also, we would like confirmation from the SDT that R7 is not describing an "N-2" contingency. To alleviate any confusion, we suggest a slight change in

wording to R7 as follows: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other, and that do not depend on any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality." We are not clear on the need for the phrase "that depend on the primary control functionality" in R7. It is ambiguous and seems unnecessary, so we ask the SDT to explain the need for this phrase.
No
We ask that our comments provided above have been appropriately considered before balloting begins. Also, we provide the following comments: In Requirement R9, the SDT changed the term "Regional Entity" to "Reliability Assurer". "Reliability Assurer" is a new term used in Version 4 of the NERC Functional Model but it is not clear if Version 4 is the latest approved Model. From looking at the NERC website, it only appears as though Version 3 is approved. We ask the SDT to confirm. Furthermore, if Version 4 is approved and Reliability Assurer is, in fact, an approved term, we believe the standard would be much clearer if Regional Entity was still used because it is much more familiar to industry at this point in time since Version 4 of the Functional Model is new. If still desired to be used, the SDT can put Reliability Assurer in parenthesis immediately following Regional Entity, i.e. "Regional Entity (Reliability Assurer)"
Individual
Michael Ayotte
ITC
Yes
Yes
Yes
We agree with the intent of the SDT, however the proposed wording is clumsy. Suggest removal of the phrase ""that provides the functionality required for maintaining compliance with all Reliabilty Standards".
Yes
Suggest removing the phrase "that depend on the primary control functionality." from the end of R7 as it is unnecessary. R7 references a "single data center" while the VSL matrix for R7 references "common facility". Common facility is much broader than data center.
No
In addition to changes suggested in Q4, we believe that VSL's for R7 should be developed for lower and medium/high. We suggest it is possible to create four VSLs for all requirements. FERC established in their June 2008 VSL order that their preference is to create a VSL for every level if possible.
Individual
Rick White
Northeast Utilities
Yes
Yes
Yes
Yes
We agree with the approach. We recommend that the term "data center" be defined. How will the independence of any single data center be evaluated? This is almost impossible to prove. What type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.
No
Once "data center" is clearly defined, we believe the standard will be ready for balloting. For lack of a general comments question, would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be be consistently used throughout the Standards.
Individual
Kathleen Goodman
ISO New England Inc.
Yes

Yes
Yes
No
We agree with the approach. We recommend that the term "data center" be defined. How will the independence of any single data center be evaluated? This is almost impossible to prove. What type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.
No
Once "data center" is clearly defined, we believe the standard will be ready for balloting. For lack of a general comments question, would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be be consistently used throughout the Standards.
Individual
Greg Rowland
Duke Energy
Yes
Yes
No
Both R4 and R5 are too long, awkwardly worded, and are subject to too much interpretation. Suggest combining them into one requirement reducing it to basically the last sentence used in R4 and R5, explaining that a tertiary is not required when the listed events occur. This could then be combined with another requirement – possibly R1.
No
This requirement raises complex issues of redundancy that go beyond the need to provide backup functionality.
No
In addition to the comments for Questions #3 and #4 above, this standard lacks sufficient clarity in the following areas to proceed to ballot: R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current (what does “current” mean?) Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center (some entities have concerns with premise of primary and secondary – they have dual “primary” centers so the notion of primary and secondary is problematic) becomes inoperable (what does “inoperable” mean – should this be clarified to mean "loss of functionality"?). R1.3. An Operating Process for keeping the backup functionality consistent (what does this mean – does this mean exact duplicate functionality, does this mean every application, process, etc needs to be exactly consistent, what is the time dimension allowed for achieve consistency?) with the primary control center. R1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in Requirement R1.2. The Operating Process shall include at a minimum: R1.6.1. A list of all entities (all is a very inclusive word – suggest something like “primary”) to notify when there is a change in operating locations. R1.6.2. Actions to manage the risk to the BES (what does this phrase mean – what is the risk to the BES associated with loss of a control center?) during the transition from primary to backup functionality as well as during outages of the primary or backup functionality. R1.7. Identification of the roles for personnel (is this by name or by function, i.e. Manager of the Control Center?) involved during the initiation and implementation of the Operating Plan for backup functionality. R3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. [Violation Risk Factor = Medium] [Time Horizon =Operations Planning] (This requirement is vague and subject to different interpretations. Suggest removing the entire requirement.) R4 and R5: See comment above on Question # 3. R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. [Violation Risk Factor = Lower] [Time Horizon = Operations Planning] R6.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1. (How significant of a change in capabilities requires a revised/approved update within 60 days?) R9. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months, shall provide a plan to its Reliability Assurer (who is this? This is apparently a new term defined in the next version of the Functional Model; since this new version is not yet approved, should it be used here?) within six calendar

months of the date when the functionality is lost, showing how it will reestablish backup capability. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] After these clarifications are made, the measures need to be closely reviewed again to assure they are aligned with the words in the requirements. For instance, the measures should not introduce new requirements as several appear to do as currently written. Likewise the VSL matrix will need to be reviewed again for alignment with the requirements.
Individual
Gregory Campoli
New York Independent System Operator
Yes
Yes
Yes
No
We agree with the approach, however we believe the term "data center" needs to be defined for this standard. How will the independence of any single data center be evaluated? This is almost impossible to prove. It is not clear what type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.
No
Once "data center" is clearly defined, we believe the standard will be ready for balloting. For lack of a general comments question, would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be be consistently used throughout the Standards.
Group
MRO NERC Standards Review Subcommittee
Michael Brytowski
MRO
Yes
With this clarification, the SDT has removed redundancy from this updated Standard, thank you. Please remove requirement 3 for the next posting of this standard.
Yes
Yes
With this clarification, the SDT has removed redundancy from this updated Standard, thank you. The MRO NSRS suggests that in R4.2 and R5.2 the SDT include R9's time line of six months to submit a plan to the RE or RC. Then R9 can be deleted.
Yes
No
R1, Requires the entity to "have a current Operating Plan". NERC defines Operating Plan as "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan". Contained in the defined term, NERC explains that an Operating Procedure and Operating Process are sub-components within the Operating Plan. R1.3 and R1.6 dictate the use of an Operating Process. R1.4 dictates the use of an Operating Procedure. This will lead to confusion within the industry. Recommend the SDT streamline these requires since they are sub-components of an Operating Plan. R1, R4, R5 and R7, Request clarification, The Operating Plan described in R1 is to contain items for "backup functionality" and at a minimum contain the sub-requirements in R1.2. Then in R4 (and in R5 for the BA and TOP), the SDT requires the RC to "have a backup control center facility that provides the functionality required for maintaining compliance with ALL Reliability Standards that depend on primary control center functionality". The PURPOSE of this Standard is for continued reliability operations of the BES (also stated in R1, and R3). FERC Order 693 states in paragraph 672, under (3) "provide for a minimum functionality to replicate the critical reliability functions of the primary control center". Note: same paragraph (5) states: "includes a Requirement that all reliability coordinators have full backup control centers". Does this proposed Standard apply to the Reliability of the BES or all Standards assigned to a RC, TOP, and BA, please clarify. R1.5, States that an entity has up to 2 hours to fully implement the backup functionality. Where did the two hour time frame

come from and what is the justification for it? There are some examples in actual emergencies that indicates the backup control center should be a substantial distance from the primary, to prevent the possibility of losing both the primary and backup facilities to the emergency, which may make it impossible to have the backup up, running, and fully functional within 2 hours. Please note the hurricanes in New Orleans, floods in Iowa. R5, The SDT is adding more components to the non-defined term of "backup functionality" as stated in the sub-requirements of R1.2. Added are the processes of "monitoring, control, logging, and alarming". If these are components of R1.2.1, then they should be added to R1.2.1, which will stream line the Standard. R2, The MRO NSRS does not believe that it is necessary for an unmanned facility (like a repeater tower) that "supports" the backup facility to have a copy of the Operating Plan and suggests the requirement be modified to clarify. R7 and R9, please clarify what backup "capability" is when the rest of the proposed standard references backup "functionality". R9, Uses the term Reliability Assurer and is undefined as stated by NERCs Reliability Functional Model (V4) "While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the Tasks that might be performed:". The term Regional Entity or Reliability Coordinator should be used since they are defined and should be contained in R9. If at a later date Reliability Assurer is approved, NERC may submit an errata to update the Requirement.
Individual
Catherine Koch
Puget Sound Energy
Yes
If the SDT believes this requirement will be covered in another location or in another standard that is most logical, then yes R3 should be deleted.
Yes
Yes, this is a necessary change. It removes this standard from interpretation by each entity and requires each to have back-up provisions. This is ciritical as many entities rely on neighboring entities to operate from day to day.
Yes
No
R7 indicates "does not depend on each other or any single data center". M7 changes the words of "any single data center" to " any common facility". The difference in these terms and how they could be interpreted is significant. The SDT should revise M7 to match R7 at a minimum. The term "common facility" could be extremely interpreted to require duplicative RTU sensors at all substations and communications systems transmitting the information to isolate the primary and the backup control centers from any dependancy. Also it would be helpful to clarify whether "depend on each other" or "common facility" includes the building the centers reside in. In previous comments, the SDT responded that "the intent (of R7) is that if the primary control center is destroyed, the backup facility will be capable of collecting the data needed to support the reliable operation of the BES.". This response could imply the centers must reside in separate buildings or at some significant distance from each other to prevent both locations from being impacted by a natural disaster. The SDT should explicitly list the components that the backup control center should not be dependent on.
No
Puget Sound Energy commented previously that the 24 month implementation timeline was not reasonable. The SDT responded that "The SDT agrees with the majority of commenters that 24 months is the correct timeframe for this standard." The questions/comments regarding the terms used in R7/M7 mentioned in response to question 4 could have significant impact on the ability for an enitity to meet within this timeframe. Until R7 is further clarified, the SDT should extend the implementation timeframe from 24 months to 36 months. Also in accordance with FERC's "Order on Violation Severity Levels Proposed by the Electric Reliability Organization," issued June 19, 2008 (Docket No. RR08-4-000), FERC has stated its preference for graduated VSLs since the application of any penalty for a violation can be more consistently and fairly applied based on the degree of the violation. In light of this, NERC should revise the proposed VSLs to include graduated violation severity levels for each and every requirement.
Group
IRC Standards Review Committee
Ben Li
IESO
Yes
Yes, this requirement should be removed – but not for the reason stated above. If there is no R3, there is no requirement that Compliance would be able to enforce in the first place. However, we believe that R3 can be removed if the first 2 sentences in R1 are modified as follows (suggested deletion in parenthesis): Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control functionality is lost. (center becomes inoperable.) This Operating Plan for backup functionality shall include the following, at a minimum:.....
Yes
This is a registration issue and really identifies an issue with the definition of the BES. A standard is not the proper

place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration.
Yes
We agree with the clarification language that is added to avoid the need for tertiary functionality. However, we wonder why R4 stipulates specifically the requirement for a "backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators" as opposed to adopting the more appropriate language used in R5, viz. "backup functionality (provided either through a backup control center facility or contracted services)". It is conceivable that an RC may arrange for backup capability with another entity as opposed to having its own backup facility. Also, it has been raised by many commenters in previous postings that it is the backup "capability" or "functionality" that matters, not the facility. We suggest R4 be revised to adopt this more flexible and appropriate language. If the different language in R4 was intended to also stipulate the need for having certified RC operators, then why is this not a requirement in R5? The two requirements should have similar if not identical language. We also think that the last part of both requirements that says: "…compliance with all Reliability Standards that depend on a primary control center functionality" is unnecessary. The responsible entity must comply with all reliability standards under either the primary functionality or backup capability condition. Isn't meeting all reliability standards and continuing to operating, monitor and maintain BES reliability the very reason for having the backup functionality?
Yes
We agree with the clarifying language, but hold the opinion that the last part of the requirement "that depend on the primary control functionality" is unnecessary. The responsible entity must comply with all reliability standards under either the primary functionality or backup capability condition, hence the need for the backup functionality.
No
Whether or not the standard is ready for ballot will depend on the extent to which the above comments are addressed. Further, the following comments also need to be addressed: VSLs for R2: The Severe condition is "The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality but no version of the plan is available at all of its control locations." There is no mention of having no version at one of the primary and backup control locations. If one version is missing, what VSL is assigned? VSLs for R3: VSL measures the extent to which an entity fails a requirement, not how impactive the failure is. However, the VSLs for R3 are assigned according to what level of VRFs the requirements have failed. Factoring the impact of a failure in the determination of the extent of failure is improper. These need to be revised. VSLs for R4: Similar comments as for VSLs for R3. Further, please note our comments and suggestions under Q3. If R4 is to be revised, the VSLs (and Measure) will need to be revised accordingly. VSLs for R5: Same comments as for VSLs for R4. We are particularly concerned with the determination of VSL based on VRFs for R3, R4 and R5. This is improper in applying the fundamental concept of VRF and VSL. We feel that the standard is not ready for balloting until these VSLs are revised to remove the VRF component.
Individual
Jason Shaver
American Transmission Company
Yes
However, it appears that R3 has not been deleted in the redlined version of the Standard posted. If the redlined version is what is being voted upon, we disagree with the language as it is currently written. The way it is currently written it would require the TOP to ensure that the other entities have backup functionality, which puts the TOP in the role of regulator, and we have no such authority. We do not have the authority to monitor backup functionality of other entities nor to compel other entities to have backup functionality. The language suggested in the last redlined version is more appropriate.
Yes
Yes
However, we recommend removing the phrase "To avoid requiring tertiary functionality" so that it reads better as a requirement.
Yes
However, the sentence is long and could be broken up into two sentences. The phrase in blue at the end of the requirement does not add value and could be removed, "…that depend on the primary control functionality".
No
R9 uses the term Reliability Assurer which is not currently defined by NERC. It should be replaced with Regional Entity. R7 and R9 use the term "backup capability". The rest of the requirements use the term "backup functionality". For consistency and clarity, it is recommended that one term is used consistently in all of the requirements. The changes or deletion of R3 needs to be clarified. If R3 is kept, then the verbiage needs to be modified as stated above. R2 should read "at the location which provides backup functionality", not "at the location supporting backup functionality". Many locations may support backup functionality, not all of which are manned and would need a copy of the plan. This re-write would remove the need for unmanned locations to have a copy of the Operating Plan.

Group
SERC OC Standards Review
Jim S. Griffith
Southern Co. Services, Inc.
Yes
Yes
No
We suggest combining R4 and R5 into one requirement and indicating that a tertiary functionality is not required for the functional entities listed. If a tertiary functionality is required, conditions for when it is required should be addressed rather than stating when it is not required. We have additional suggested revisions to R4 and R5, which are included in the comments for Question 5.
No
The language should be more specific in indicating that an event that could make the primary center inoperable should not make the backup functionality inoperable. We suggest adding language in R1 that addresses mitigation of single points of failure and, therefore, eliminate R7.
No
We have the following comments regarding the noted requirements of this standard: R1: The word, “current”, should be removed from the language of the requirement. R1: What is the difference between “operability” “and functionality”? Are they the same? R1.1: Delete "for a prolonged period of time." R1.3: What does “consistent” mean? – does it mean "adequate to meet compliance"? 1.6.2: This requirement appears to be redundsant to R1.6. R2: The word, “current”, should be removed from the language of the requirement. R4: In the first sentence, change "facility" to "functionality" and delete all remaining language of the sentence following "functionality. R5: In the first sentence, delete all remaining language of the sentence following "functionality". R6.1: We suggest that changes that are necessary for the operator to implement the back-up plan should be updated within 60 days - all other changes shall be addressed during the annual review. R8: When does the first test have to be performed, following implementation, to be compliant? - one day or within one year after implementation? We request that "annual" be replaced with "a calendar year". R8.1: We suggest adding the word "simulated' in front of "loss of primary control". General Comment: Measures and VSLs should use the same words and be consistent with the requirements of the Standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on the Third Draft of EOP-008-1 — Loss of Control Center Functionality for the Backup Facilities SDT (Project 2006-04)

The Backup Facilities Standard Drafting Team thanks all commenters who submitted comments on the third draft of EOP-008-1 — Loss of Control Center Functionality standard. This standard was posted for a 30-day public comment period from March 17, 2009 through April 15, 2009. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 36 sets of comments, including comments from more than 130 different people from over 60 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Backup_Facilities.html

Due to the industry comments provided, the SDT has revised the following: Requirements R1, R2, R5, R7, and part 8.1 under R8.

The SDT does not feel that any of these changes are significant in nature and recommends that this project be moved to the balloting stage.

There were several minority viewpoints expressed during the review period:

- Some commenter's expressed a concern regarding the 24 month implementation period for this standard. The SDT weighed these concerns carefully and feels that 24 months is the appropriate time frame. This finding is based on the idea that most of the applicable entities already have appropriate backup functionality in place and for those who do not, 24 months seems to be an acceptable period of time to reach compliance.
- Some comments were received on the amount of transition time that is being allowed in the revised standard. Concerns were expressed that the time had been increased and therefore, reliability was being unduly impacted. The SDT does not agree with this position nor did the majority of respondents. The revised standard is much tighter than the original in terms of what must be done in the transition period and thus should increase reliability.

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 Vice President and 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.

Index to Questions, Comments, and Responses

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.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Randy MacDonald	New Brunswick System Operator	NPCC	2
3.	Tony Elacqua	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manny Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Brian Evans-Mongeon	Utility Services	NPCC	6
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Michael Gildea	Constellation Energy	NPCC	6
12.	Chris Orzel	FPL/NextEra Energy	NPCC	5
13.	Kathleen Goodman	ISO - New England	NPCC	2

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

	Additional Member	Additional Organization	Region	Segment Selection
14.	David Kiguel	Hydro One Networks Inc.	NPCC	1
15.	Michael Schiavone	National Grid	NPCC	1
16.	Rick White	Northeast Utilities	NPCC	1
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
19.	Brian Hogue	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Gerry Beckerle	Ameren Services	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Hackman	Ameren	SERC	1
2.	Mike Wedel	Ameren	SERC	1
3.	Dennis Dare	Ameren	SERC	1
4.	Gene Warnecke	Ameren	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dave Thorne	Pepco	RFC	1
2.	Vic Davis	Delmarva Power & Light	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	JT Wood	Southern Company Transmission	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Marc Butts		SERC	1
2.	Jim Griffith		SERC	1
3.	Lee Taylor		SERC	1
4.	Monroe Landrum		SERC	1
5.	Steve Corbin		SERC	1
6.	Steve Williamson		SERC	1
7.	Tom Sims		SERC	1
8.	Mike Sanders		SERC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Transmission Technical Operations	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Barb Kedrowski	We Energies	RFC	3, 4, 5
2.	Jim Cyrulewski	JDRJC Associates	RFC	8

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dave Folk	FE	RFC	1, 3, 4, 5, 6
2.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
3.	John Reed	FE	RFC	1
4.	Andy Hunter	FE	RFC	1
5.	John Martinez	FE	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MP	MRO	1, 3, 5, 6
2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Terry Bilke	MISO	MRO	2
4.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Jim Haigh	WAPA	MRO	1, 6
7.	Terry Harbour	MEC	MRO	1, 3, 5, 6
8.	Joseph Knight	GRE	MRO	1, 3, 5, 6
9.	Scott Nickels	RPU	MRO	3, 4, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	10. Dave Rudolph	BEPC	MRO	1, 3, 5, 6									
	11. Eric Ruskamp	LES	MRO	1, 3, 5, 6									
	12. Pam Sordet	XCEL	MRO	1, 3, 5, 6									
9.	Group	Jim S. Griffith	SERC OC Standards Review	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eugene Warnecke	Ameren	SERC	1, 3, 5
2.	Robert Thomasson	Big Rivers elec Coop	SERC	1, 3, 5
3.	Steve Fritz	ACES Power		
4.	John Neagle	AECI		
5.	Eugene Warnecke	Ameren		
6.	Gerry Beckerle	Ameren		
7.	Robert Thomasson	BREC		
8.	Alisha Anker	CWLP		
9.	Carl Eng	Dominion VP		
10	Jack Kerr	Dominion VP		
11.	David McRee	Duke Energy		
12.	Greg Stone	Duke Energy		
13.	Sam Holeman	Duke Energy		
14.	George Carruba	EKPC		
15.	Michelle Bourg	Entergy		
16.	Paul Turner	GASOC		
17.	Wayne Pourciau	GASOC		
18.	Keith Porterfield	GSOC		
19.	Dan Jewell	LA Generating		
20.	Tim Lejeune	LA Generating		
21.	Jason Marshall	MISO		
22.	Michael Bryson	PJM		
23.	Tim Hattaway	PowerSouth		

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

24.	Brady Williams	Progress Energy
25.	Phil Creech	Progress Energy
26.	Sammy Roberts	Progress Energy
27.	Glenn Stephens	Santee Cooper
28.	Rene' Free	Santee Cooper
29.	Al McMeekin	SCE&G
30.	Alvin Lanton	SIPC
31.	John Rembold	SIPC
32.	Gary Hutson	SMEPA
33.	Jim Griffith	Southern
34.	Lee Taylor	Southern
35.	Marc Butts	Southern
36.	Monroe Landrum	Southern
37.	Steve Corbin	Southern
38.	Steve Williamson	Southern
39.	Tom Sims	Southern
40.	Dave Pond	TVA
41.	Alan Jones	Yadkin

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Ben Li	IRC Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Matt Goldgerg	ISO-NE	NPCC	2
2. Anita Lee	AESO	WECC	2
3. James Castle	NYISO	NPCC	2
4. Steve Myers	ERCOT	ERCOT	2
5. Patrick Brown	PJM	RFC	2
6. Charles Yeung	SPP	SPP	2
7. Lourdes Estrada-Salinero	CAISO	WECC	2
8. Bill Phillips	MISO	MRO	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Individual	John Tolo	Tucson Electric Power	X									
12.	Individual	Dan Rochester	Ontario IESO		X								
13.	Group	Patrick Brown	PJM's NERC & Regional Coordination Department		X								
14.	Individual	Jack Kerr	Dominion Virginia Power	X									
15.	Individual	Al McMeekin	South Carolina Electric & Gas Company	X		X		X					
16.	Individual	Randy Schimka	San Diego Gas and Electric Co	X		X							
17.	Individual	Thomas Fung	BCTC	X	X								
18.	Individual	Chris Scanlon	Exelon	X		X		X	X				
19.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
20.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
21.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
22.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
23.	Individual	Thad Ness	American Electric Power (AEP)	X		X		X	X				
24.	Individual	Frank Gaffney, Regulatory Compliance Officer	FMPA and its ARP Participants Listed as Follows: City of Vero Beach; Kissimmee Utility Authority; and Beaches Energy Services	X		X	X	X	X				
25.	Individual	D. Bryan Guy	Progress Energy	X		X	X						

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
27.	Individual	Rao Somayajula	ReliabilityFirst Corporation										X
28.	Individual	Edward J Davis	Entergy Services, Inc	X		X		X	X				
29.	Individual	Michael Ayotte	ITC	X									
30.	Individual	Rick White	Northeast Utilities	X									
31.	Individual	Kathleen Goodman	ISO New England Inc.		X								
32.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
33.	Individual	Gregory Campoli	New York Independent System Operator		X								
34.	Individual	Catherine Koch	Puget Sound Energy	X									
35.	Individual	Jason Shaver	American Transmission Company	X									
36.	Individual	Mike Gammon	KCP&L										

1. **The SDT has discovered that Compliance is already enforcing Requirement R3 as part of its review of delegation agreements. Therefore, it appears that this requirement could be deleted. Do you agree that this requirement can be deleted? If not, please provide specific reasons why it shouldn't be deleted.**

Summary Consideration:

While the majority of commenters agreed that this requirement could be deleted, several commenters pointed out a possible reliability gap if this requirement were to be removed. Several others indicated that the requirement could be deleted but the concept needed to remain. After additional research into the topic, the SDT feels that this requirement is still necessary for reliability. No requirement covering this situation has been found in other documents or the Rules of Procedure, therefore, the requirement will be retained.

However, the SDT did make a clarifying change to Requirement R1 at the suggestion of a commenter.

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center functionality is lost.

Organization	Yes or No	Question 1 Comment
Dominion Virginia Power	No	If there is a reliability need for backup capabilities for delegated tasks, then this should be explicitly stated in a reliability standard. It should not be implied or be something that. on review, Compliance deems is necessary but that is without a clear basis in the standards.
Xcel Energy	No	If something is monitored by Compliance, then there needs to be an associated standard/requirement. In this case, what standard or requirement would apply if this were to be deleted?
Oncor Electric Delivery	No	This requirement shoud stay in EOP-008-1 because the "other entities" referred to in R3 are the entities that have actual device control of BES elements (very true in ERCOT).
PacifiCorp	No	Requirement 3 should be left in the Standard. While it may be redundant with present efforts to review delegation agreements, it stipulates the intent of the Standard: that entities remain responsible for operations on the BES even if those duties are implemented via others. Keeping this requirement in the Standard, explicitly, insures that all entities understand the requirements and intent of this Standard, regardless of changes that may occur in the future regarding a separate process associated with review of delegation agreements. The process to review delegation agreements can change without industry input, as that process is not subject to the same approval requirements as those necessary when a Standard is created or modified.

Organization	Yes or No	Question 1 Comment
Response: Based on your comments and those of others, the SDT has retained Requirement R3.		
KCP&L	No	Cannot render a judgement regarding deletion of R3 without knowledge of the content of the delegation agreements referred to here. As a result, cannot recommend removal or maintiaining requirement R3 as proposed here.
Response: Thank you for your response.		
IRC Standards Review Committee	Yes	Yes, this requirement should be removed - but not for the reason stated above. If there is no R3, there is no requirement that Compliance would be able to enforce in the first place. However, we believe that R3 can be removed if the first 2 sentences in R1 are modified as follows (suggested deletion in parenthesis): Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control functionality is lost. (center becomes inoperable.) This Operating Plan for backup functionality shall include the following, at a minimum:.....
Ontario IESO	Yes	Yes, this requirement should be removed - but not for the reason stated above. If there is no R3, there is no requirement that Compliance would be able to enforce in the first place. However, we believe that R3 can be removed if R1 is modified as follows (suggested deletion in parenthesis): "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control functionality is lost. (center becomes inoperable.) This Operating Plan for backup functionality shall include the following, at a minimum:"
Response: Requirement R1 has been changed as suggested. However, Requirement R3 will be retained as described in the summary response. **R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center functionality is lost.		
American Transmission Company	Yes	However, it appears that R3 has not been deleted in the redlined version of the Standard posted. If the redlined version is what is being voted upon, we disagree with the language as it is currently written. The way it is currently written it would require the TOP to ensure that the other entities have backup functionality, which puts the TOP in the role of regulator, and we have no such authority. We do not have the authority to monitor backup functionality of other entities nor to compel other entities to have backup functionality. The language suggested in the last redlined version is more appropriate.

Organization	Yes or No	Question 1 Comment
Response: In the opinion of the SDT, if a Reliability Coordinator, Balancing Authority, or Transmission Operator has delegated particular primary control center functionality to another entity then it is the responsibility of that Reliability Coordinator, Balancing Authority, or Transmission Operator to ensure that backup functionality exists, either by the Reliability Coordinator, Balancing Authority, or Transmission Operator, the delegated entity, or a 3rd entity. Requirement R1 has been adjusted to clarify this position. Requirement R3 has been retained as described above. **R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center functionality is lost.		
Northeast Power Coordinating Council	Yes	
Ameren Services	Yes	
Pepco Holdings, Inc - Affiliates	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
Midwest ISO Standards Collaborators	Yes	
FirstEnergy	Yes	We agree that the compliance concept of delegation agreements should not reside in this or any reliability standard. The rules governing delegation of tasks should be clearly described in the NERC Rules of Procedure or Registration Criteria.
MRO NERC Standards Review Subcommittee	Yes	With this clarification, the SDT has removed redundancy from this updated Standard, thank you. Please remove requirement 3 for the next posting of this standard.
SERC OC Standards Review	Yes	
Tucson Electric Power	Yes	I agree R3 should be deleted
PJM's NERC & Regional Coordination Department	Yes	We agree that Requirement R3 should be deleted. Backup capability is defined as "the ability to maintain situational awareness and continue to comply with reliability standards when primary control center facilities are not operational" as such, "backup capability" does not need to equate to "backup facility." The standard

Organization	Yes or No	Question 1 Comment
		should be written to require the necessary/essential functionality (not require another facility) when the primary capability is lost (as is done in R1). Simply, the standard needs to require the principle need, yet not be too prescriptive on how that is accomplished.
South Carolina Electric & Gas Company	Yes	
San Diego Gas and Electric Co	Yes	
BCTC	Yes	
Exelon	Yes	
E.ON U.S.	Yes	
American Electric Power (AEP)	Yes	
FMPA and its ARP Participants Listed as Follows: City of Vero Beach; Kissimmee Utility Authority; and Beaches Energy Services	Yes	
Progress Energy	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
ReliabilityFirst Corporation	Yes	
Entergy Services, Inc	Yes	
ITC	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 1 Comment
ISO New England Inc.	Yes	
Duke Energy	Yes	
New York Independent System Operator	Yes	
Puget Sound Energy	Yes	If the SDT believes this requirement will be covered in another location or in another standard that is most logical, then yes R3 should be deleted.
Response: Thank you for your response. The SDT has made a slight adjustment to Requirement R1 to clarify this item. However, based on other industry comments, the SDT has decided to retain Requirement R3 as described in the summary response above. **R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center functionality is lost.		

2. **The SDT has made a change in the applicability of the Transmission Operator (see Section 4.1.2) so that all Transmission Operators are treated equally. Do you agree with the change that was made? If not, please provide specific suggestions for improvement.**

Summary Consideration:

The vast majority of comments received support the change in applicability. However, a clarifying change was made to Requirement R5 to accommodate the concern brought up by FMPA.

R5. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during:

Organization	Yes or No	Question 2 Comment
American Electric Power (AEP)	No	It seems that 200 kV provides a reasonable demarcation of transmission facilities on the Bulk Electric System; below 200 kV are generally more localized distribution facilities. Within this segment, the existing applicability treated all Transmission Owners equally.
Response: Based on comments that the SDT has received, the industry consensus seems to be that this standard should apply to all Transmission Operators. The SDT feels that this is a registration issue that doesn't belong in this standard. No change made.		
FMPA and its ARP Participants Listed as Follows: City of Vero Beach; Kissimmee Utility Authority; and Beaches Energy Services	No	We agree that all Transmission Operators should have a plan for loss of control center functionality, but, as written, the standard, particularly Requirement 5, seems to force all BAs and TOPs to have a back-up control center or contract for services for one (see paranthetical in R5 and M5). We believe that smaller BAs and TOPs can meet all of the requirements within the standard for backup functionality without a back-up control center or contracted services. For instance, we know of at least one TOP that is only a TOP for one substation, and therefore existing substation facilities can fulfill all of the backup functionality specified in the standard without the need for a backup control center. Similarly, we know of at least one BA who only has one power plant in its BA area, meaning that the BA can be operated from the power plant without a backup control center. We suggest striking the paranthetical in R5 and M5, or expanding it to read "provided either through a backup control center facility, contracted services, or other means".
Response: The SDT understands the concerns raised here and has tried to be cognizant of the impact of this revised standard on smaller entities. However, 'other means' is an unmeasurable term. The SDT has made every effort to describe functionality instead of bricks and mortar facilities. The SDT believes that in the particular cases cited in the comment, that if the original location fulfills the duties of a control center and allows the entity to be compliant with all relevant		

Organization	Yes or No	Question 2 Comment
Reliability Standards, then the backup cited would be acceptable as well as long as all relevant Reliability Standards are complied with. However, the SDT has removed the term 'backup control center' from the parenthetical expression in requirement R5 and M5 to clarify this point. **R5**. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during:		
Northeast Power Coordinating Council	Yes	
Ameren Services	Yes	
Pepco Holdings, Inc - Affiliates	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	Not sure if it should be applicable to small TOPs.
Midwest ISO Standards Collaborators	Yes	
FirstEnergy	Yes	
MRO NERC Standards Review Subcommittee	Yes	
IRC Standards Review Committee	Yes	This is a registration issue and really identifies an issue with the definition of the BES. A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation should be handled in registration.
SERC OC Standards Review	Yes	
Tucson Electric Power	Yes	

Organization	Yes or No	Question 2 Comment
Ontario IESO	Yes	A standard is not the proper place to address registration and BES definition issues. The applicability should be just to the TOP and any limitation shouldbe handled in registration.
PJM's NERC & Regional Coordination Department	Yes	
Dominion Virginia Power	Yes	
South Carolina Electric & Gas Company	Yes	
San Diego Gas and Electric Co	Yes	
BCTC	Yes	
Exelon	Yes	
Xcel Energy	Yes	
E.ON U.S.	Yes	
Oncor Electric Delivery	Yes	
PacifiCorp	Yes	
Progress Energy	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
ReliabilityFirst Corporation	Yes	
Entergy Services, Inc	Yes	

Organization	Yes or No	Question 2 Comment
ITC	Yes	
Northeast Utilities	Yes	
ISO New England Inc.	Yes	
Duke Energy	Yes	
New York Independent System Operator	Yes	
Puget Sound Energy	Yes	Yes, this is a necessary change. It removes this standard from interpretation by each entity and requires each to have back-up provisions. This is ciritical as many entities rely on neighboring entities to operate from day to day.
American Transmission Company	Yes	
KCP&L	Yes	

Response: Thank you for your response. A clarifying change was made to Requirement R5 and M5 to accommodate the concerns brought up by FMPA.

> **R5**. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during:

3. **The SDT has provided clarifications to the applicability of reliability standards, avoiding the need for tertiary functionality, and when backup functionality is not required in Requirements R4 and R5. Do you agree with these changes? If not, please provide specific suggestions for improvement.**

Summary Consideration: The majority of the commenters agreed with the SDT's position although some questions were raised as to the exact wording of some of the requirements. The SDT has provided explanations for the positions taken or agreed to change the requirements. Due to industry comments, Requirements 4.1, 4.2, 5.1, and 5.2 have been changed to be parts of bulleted lists and Requirement R5 was changed as follows:

R5. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during:

Organization	Yes or No	Question 3 Comment
KCP&L	No	Agree with the intent of the SDT regarding the need to avoid back-up plans on top of back-up plans, however, the sub-requirements may be in need of some additional work. It appears the intent of requirements R4 & R5 is to prevent the need to develop a temporary back-up plan when either the primary or back-up capability becomes temporarily unavailable. Recommend removal of sub-requirements R4.2 an R5.2 as the condition for the unexpected loss of either the primary of back-up capability is covered by R9. Recommend an alignment of sub-requirement R4.1 and R4.2 with the 6 month timing requirement in R9. If it is OK to be without a back-up plan for up to 6 months for the unanticipated loss of the primary or back-up capability why is two weeks such a concern for a planned loss?
Response: The SDT does not agree that unexpected short-term loss of the primary or backup capability is covered by Requirement R9. The language of Requirement R9 is intended to cover a major loss of functionality, such as a catastrophic event. Other unplanned events such as a failure of the backup EMS or other equipment could cause a short term loss of functionality which Requirements R4.2 and R5.2 (now parts of bulleted lists) are intended to address. No change made.		
Ameren Services	No	R4 and R5 should be combined and all three entities, RC, BA, and TOP should be required to have at least two facilities that are independent of each other to the extent that compliance to NERC Standards can be maintained from those facilities. These facilities maybe a primary facility, with backup(s), or multiple primary facilties. Facilities may be shared with other entities, but must be able to meet the compliance requirements of all the entities sharing the facility. If an entitiy has two independent facilities that they can operate from, whether shared or not, a tertiary is not required. If for any reason an entity does not have at least two facilities to operate

Organization	Yes or No	Question 3 Comment
		independantly from, that entity must prepare a mitigation plan acceptable to their Regional Entity.
Response: The language of Requirements R4 & R5 follows the directives supplied in Order 693. The standard has been drafted to take those directives into account and the industry comments have not provided a consensus opinion that the direction provided by FERC should be modified with respect to different treatment of the Reliability Coordinator. The SDT has attempted to allow certain time periods to be allowed for planned and unplanned outages without a tertiary set of functionality being provided. If the entity does not maintain backup capability as specified in the standard, a non-compliance event will occur and a mitigation plan will have to be developed and submitted to the Regional Entity. The SDT does not agree that the standard should address mitigation measures for non-compliance in the requirements of the standard. No change made.		
Southern Company Transmission	No	We suggest combining R4 and R5 into one requirement and indicating that a tertiary functionality is not required for the functional entities listed. If a tertiary functionality is required, conditions for when it is required should be addressed rather than stating when it is not required. We have additional suggested revisions to R4 and R5, which are included in the comments for Question 5.
SERC OC Standards Review	No	We suggest combining R4 and R5 into one requirement and indicating that a tertiary functionality is not required for the functional entities listed. If a tertiary functionality is required, conditions for when it is required should be addressed rather than stating when it is not required. We have additional suggested revisions to R4 and R5, which are included in the comments for Question 5.
Response: The language of Requirements R4 & R5 follows the directives supplied in Order 693. The standard has been drafted to take those directives into account and the industry comments have not provided a consensus opinion that the direction provided by FERC should be modified with respect to different treatment of the Reliability Coordinator. See response to comments on Question 5.		
Bonneville Power Administration	No	If we have a planned outage for 3 weeks (longer than 2 weeks criteria) of either the primary or the backup facility we need a alternate (tertiary facility under the new requirements) facility in place. Current standard says we need interim provisions during transfer if it will take longer than 1 hour to implement plan. New standard has a 2 hour window requirement for the plan to be fully implemented.
Response: Planned outages that last more than 2 weeks must be reported to your Regional Entity and a mitigation plan must be submitted. The SDT was not able to discern a question from these statements.		
Midwest ISO Standards	No	We agree with the intent of the changes and support the need to avoid creating a requirement for a tertiary control center. However, we believe the changes are confusing and there is large amount of extraneous information that

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Collaborators</td><td></td><td>only confuses the mater. For instance, there is no need to state "that provides the functionality required for maintaining compliance with all Reliabilty Standards". RCs are already required to comply with all applicable standards regardless of this statement and whether they are operating from their primary or backup facility. This clause does nothing to increase or strengthen those requirements and is unneeded.

We suggest modifying R4 to:"Each RC shall have a backup control center facility available except:during planned outages of the primary or backup facilities of two weeks or less or during uplanned outages of the primary or backup facilities."

Likewise, we suggest the following wording for R5:"Each BA and TOP shall have backup functionality that includes monitoring, control, logging, and alarming available execpt:during planned outages of the primary or backup facilities of two weeks or less or during uplanned outages of the primary or backup facilities."</td></tr>
<tr><td>Exelon</td><td>No</td><td>We agree with the intent of the changes and support the need to avoid creating a requirement for a tertiary control center. However, we believe the changes are confusing and there is large amount of extraneous information that only confuses the mater. For instance, there is no need to state "that provides the functionality required for maintaining compliance with all Reliabilty Standards". RCs are already to comply with all applicable standards regardless of this statement and whether they are operating from their primary or backup facility. This clause does nothing to increase or strengthen that requirement and is unneeded.

We suggest modifying R4 to:"Each RC shall have a backup control center facility available except:during planned outages of the primary or backup facilities of two weeks or less or during uplanned outages of the primary or backup facilities."

Likewise, we suggest the following wording for R5:"Each BA and TOP shall have backup functionality that includes monitoring, control, logging, and alarming available execpt:during planned outages of the primary or backup facilities of two weeks or less or during uplanned outages of the primary or backup facilities."</td></tr>
<tr><td colspan="3">Response: The phrase "that provides the functionality required for maintaining compliance with all Reliability Standards" also includes the following qualifier: "that depend on primary control center functionality" The intent of this language is to make it clear that the backup functionality includes all aspects of the Reliability Standards that apply to a control center, and only those. There are other standards that apply to processes such as long term planning activities that are outside the scope of activities required to be performed at a control center. Those activities do not have to be replicated in the backup control functionality. The SDT believes this is an important distinction. No change made due to this comment.

R4 & R5: The SDT appreciates you comment, but believes that the requirement as written contains sufficient detail to express the intent of the standard. No change made due to this comment.</td></tr>
<tr><td>Dominion Virginia Power</td><td>No</td><td>As written, the clarifications do not appear to have avoided the need for tertiary facilities/functionalities. In fact, the proposed wording implies that there is a need for tertiary facilities/functionalities if a planned outage of more</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		than two weeks is anticipated. An RC or TOP is not likely to assume that some day they might have to plan an outage in excess of two weeks and then go ahead and acquire tertiary facilities/functionalities to have on hand just in case. Therefore, it should be clear that, under normal operations (all systems "Go"), only primary and adequate backup facilities/functionalities are required for compliance. Failure to provide adequate backup in the first place would constitute non-compliance. Under degraded operations (loss of primary facilities/functionalities or loss of the adequate backup facilities/functionalities previously provided), there should be separate and specific requirements for plans an RC or TOP should make and/or actions they should take until normal operations are restored (similar to what R1.6.2 now says but promoted to a stand-alone requirement). Compliance under degraded operations would be evaluated based on these new requirements specific to degraded operations instead of the original requirements to have backup facilities/functionalities. This eliminates the conundrum of being non-compliant when primary or backup facilities/functionalites are lost.Tertiary facilities/functionalities are not cost effective and are not necessary to achieve an Adequate Level of Reliability. Some entities, especially those who operate markets, may chose to acquire tertiary facilities/functionalities for various reasons. In doing so, they are choosing to "plan and operate their portion of the System to achieve a level of reliability that is above the standards." (Words in quotes are from the NERC definition of Adequate Level of Reliability.)
Response: Planned outages that last more than 2 weeks must be reported to your Regional Entity and a mitigation plan must be submitted. This is standard operating procedure so no change to the requirements is necessary.		
South Carolina Electric & Gas Company	No	Suggested language for R4: Each Reliability Coordinator shall have backup control center functionality provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators for maintaining compliance with all applicable Reliability Standards. No tertiary functionality is required.Suggested language for R5: Each Balancing Authority and Transmission Operator shall have backup functionality provided through a backup control center facility or contractual services, for maintaining compliance with all applicable Reliability Standards. No tertiary functionality is required.
ITC	Yes	We agree with the intent of the SDT, however the proposed wording is clumsy. Suggest removal of the phrase ""that provides the functionality required for maintaining compliance with all Reliabilty Standards".
Response: The phrase "that provides the functionality required for maintaining compliance with all Reliability Standards" also includes the following qualifier: "that depend on primary control center functionality" The intent of this language is to make it clear that the backup functionality includes all aspects of the Reliability Standards that apply to a control center, and only those. There are other standards that apply to processes such as long term planning activities that are outside the scope of activities required to be performed at a control center. Those activities do not have to be replicated in the backup control functionality. The SDT believes this is an important distinction. No change made due to this comment.		
E.ON U.S.	No	R5 - The first sentence is long and redundant. Compliance is required whether operating from the primary facility

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>or backup facility. The sentence could end after "?maintaining compliance".

Also, R5.1 and 5.2 should not be sub-requirements but rather bullets.

Finally, the standard should explicitly state that tertiary functionality is not required.</td></tr>
<tr><td colspan="3">Response: The phrase "that provides the functionality required for maintaining compliance with all Reliability Standards" also includes the following qualifier: "that depend on primary control center functionality" The intent of this language is to make it clear that the backup functionality includes all aspects of the Reliability Standards that apply to a control center, and only those. There are other standards that apply to processes such as long term planning activities that are outside the scope of activities required to be performed at a control center. Those activities do not have to be replicated in the backup control functionality. The SDT believes this is an important distinction.

The SDT agrees that having Requirements R4.1, R4.2, R5.1, and R5.2 as sub-requirements is awkward, and has changed the draft so that the language is included as bullets.

The standard already states that tertiary functionality is not required. No change made.</td></tr>
<tr><td>Progress Energy</td><td>No</td><td>We suggest combining R4 and R5 into one requirement.</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>Both R4 and R5 are too long, awkwardly worded, and are subject to too much interpretation. Suggest combining them into one requirement reducing it to basically the last sentence used in R4 and R5, explaining that a tertiary is not required when the listed events occur. This could then be combined with another requirement ? possibly R1.</td></tr>
<tr><td colspan="3">Response: The language of Requirements R4 & R5 follows the directives supplied in Order 693. The standard has been drafted to take those directives into account and the industry comments to the standards language have not provided a consensus opinion that the direction provided by FERC should be modified with respect to different treatment of the Reliability Coordinator.</td></tr>
<tr><td>FirstEnergy</td><td>Yes</td><td>However, the change to R4 that requires "certified Reliability Coordinator Operators" should be carried through to R5 to require BAs and TOPs delegate tasks to NERC certified BAs and TOPs. This will make R4 and R5 consistent.</td></tr>
<tr><td colspan="3">Response: The SDT agrees with the suggested change to ensure that backup functionality is performed by certified operators. Requirement R5 has been changed accordingly.

R5. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator’s primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during:</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Subcommittee	Yes	With this clarification, the SDT has removed redundancy from this updated Standard, thank you. The MRO NSRS suggests that in R4.2 and R5.2 the SDT include R9's time line of six months to submit a plan to the RE or RC. Then R9 can be deleted.
Response: The language of Requirement R9 is intended to cover a major loss of functionality, such as a catastrophic event. Other unplanned events such as a failure of the backup EMS, or other equipment could cause a short term loss of functionality which Requirements R4.2 and R5.2 (now parts of bulleted lists) are intended to address.		
IRC Standards Review Committee	Yes	We agree with the clarification language that is added to avoid the need for tertiary functionality. However, we wonder why R4 stipulates specifically the requirement for a "backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators" as opposed to adopting the more appropriate language used in R5, viz. "backup functionality (provided either through a backup control center facility or contracted services)". It is conceivable that an RC may arrange for backup capability with another entity as opposed to having its own backup facility. Also, it has been raised by many commenters in previous postings that it is the backup "capability" or "functionality" that matters, not the facility. We suggest R4 be revised to adopt this more flexible and appropriate language.If the different language in R4 was intended to also stipulate the need for having certified RC operators, then why is this not a requirement in R5? The two requirements should have similar if not identical language. We also think that the last part of both requirements that says: "compliance with all Reliability Standards that depend on a primary control center functionality" is unnecessary. The responsible entity must comply with all reliability standards under either the primary functionality or backup capability condition. Isn't meeting all reliability standards and continuing to operating, monitor and maintain BES reliability the very reason for having the backup functionality?
Ontario IESO	Yes	We agree with the clarification language that is added to avoid the need for tertiary functionality. However, we wonder why R4 stipulates specifically the requirement for a "backup control centre facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators" as opposed to adopting the more appropriate language used in R5, viz. "backup functionality (provided either through a backup control center facility or contracted services)". It is conceivable that an RC may arrange for backup capability with another entity as opposed to having its own backup facility. Also, it has been raised by many commenters in previous postings that it is the backup "capability" or "functionality" that matters, not the facility. We suggest R4 be revised to adopt this more flexible and appropraite language.If the different language in R4 was intended to also stipulate the need for having certified RC operators, then why is this not a requirement in R5? The two requirements should have similar if not identical language. We also think that the last part of both requirements that says: "compliance with all Reliability Standards that

Organization	Yes or No	Question 3 Comment
		depend on a primary control center functionality" is unnecessary. The responsible entity must comply with all reliability standards under either the primary functionality or backup capability condition. Isn't meeting all reliability standards and continuing to operating, monitor and maintain BES reliability the very reason for having the backup functionality?
Response: The language of Requirements R4 & R5 follows the directives supplied in Order 693. The standard has been drafted to take those directives into account and the industry comments to the standards language have not provided a consensus opinion that the direction provided by FERC should be modified with respect to different treatment of the Reliability Coordinator. The phrase "that provides the functionality required for maintaining compliance with all Reliability Standards" also includes the following qualifier: "that depend on primary control center functionality" The intent of this language is to make it clear that the backup functionality includes all aspects of the Reliability Standards that apply to a control center, and only those. There are other standards that apply to processes such as long term planning activities that are outside the scope of activities required to be performed at a control center. Those activities do not have to be replicated in the backup control functionality. The SDT believes this is an important distinction.		
PJM's NERC & Regional Coordination Department	Yes	We agree that the clarifications provided are correct and that there is no need for 'tertiary functionality.' However, it appears some clarifying language is needed to better articulate the need for "backup capability." In addition, while the language in R4 is fairly clear, the language in R5 is very confusing and has the affect of including multiple requirements in one run on sentence. This will pose problems both in terms of trying to adhere to the requirement as well as trying to audit the requirement. Although it appears the SDT was looking to include acceptable risk for time periods of two weeks or less for planned outages when backup functionality is not required, we do not believe that there should be any reference to 'tertiary facility' or 'backup facility' in this requirement with respect to planned or unplanned outages. As such, we believe these sub requirements can be omitted. We propose the following language to the SDT for Requirements 4 and 5 with the caveat that the SDT must resolve the frequency for which it is acceptable to not have backup capability (it shoud be a risk-informed basis):R4. Each Reliability Coordinator shall have backup capability (provided either through a backup control center or through contracted services or other pre-established means) utilizing certified Reliability Coordinator operators and the functionality necessary to maintain compliance with all reliability standards and the situational awareness provided by the primary control center when it is operational. The unavailability of backup capability is permissable for periods of up to two weeks per _________ due to planned or unplanned outages as long as the Responsible Entity implements continuing and reasonable efforts to restore its backup capability. R.5. Each Balancing Authority and Transmission Operator shall have backup capability (provided either through a backup control center or through contracted services or other pre-established means) that includes monitoring, control, logging, and alarming functionality necessary to maintain compliance with all reliability standards and the situational awareness provided by the primary control center when it is operational. The unavailability of backup

Organization	Yes or No	Question 3 Comment
		capability is permissable for periods of up to two weeks per _________ due to planned or unplanned outages as long as the Responsible Entity implements continuing and reasonable efforts to restore its backup capability.
Response: The SDT agrees that these statements are clarifying in nature and has changed this draft so that the language from Requirements R4.1, R4.2, R5.1, and R5.2 are included as bullet items in Requirements R4 and R5, not as sub-requirements. The language of Requirements R4 & R5 follows the directives supplied in Order 693. The standard has been drafted to take those directives into account and the industry comments have not provided a consensus opinion that the direction provided by FERC should be modified with respect to different treatment of the Reliability Coordinator. Additionally, the decision to have a 2 week consecutive planned outage period and no specific limit on unplanned outages was a result of the comments to draft 2. Few suggestions were made to change this language concerning the time period of unavailability, so the language will remain as is in draft 3.		
Xcel Energy	Yes	Recommend R5.2 include a time limit (e.g. 14 days) as well; may need to add a cumulative limit per year on both as well to prevent abuse.Enhance the allowable planned outage time as a reference to days (e.g. 14 days), rather than weeks, for more clarity.
Response: The decision to have a 2 week consecutive planned outage period and no specific limit on unplanned outages was a result of the comments to draft 2. Few suggestions were made to change this language concerning the time period of unavailability, so the language will remain as is in draft 3.		
American Transmission Company	Yes	However, we recommend removing the phrase "To avoid requiring tertiary functionality" so that it reads better as a requirement.
Response: The SDT has reviewed your comment and does not believe that removing the indicated phrase provides any additional clarity. No change made.		
Oncor Electric Delivery	Yes	
PacifiCorp	Yes	
American Electric Power (AEP)	Yes	
FMPA and its ARP Participants Listed as Follows: City of Vero Beach; Kissimmee Utility Authority; and Beaches Energy Services	Yes	
Hydro-Québec TransEnergie	Yes	

Organization	Yes or No	Question 3 Comment
(HQT)		
ReliabilityFirst Corporation	Yes	
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
ISO New England Inc.	Yes	
New York Independent System Operator	Yes	
Puget Sound Energy	Yes	
Northeast Power Coordinating Council	Yes	
Pepco Holdings, Inc - Affiliates	Yes	
Tucson Electric Power	Yes	
San Diego Gas and Electric Co	Yes	
BCTC	Yes	
Response: Thank you for your response.		

4. **The SDT has clarified the issue of independence of facilities in Requirement R7. Do you agree with this change? If not, please make specific suggestions for improvement.**

Summary Consideration: With the exception of some concerns raised as to specific wording in Requirement R7, the majority of respondents agreed with the SDT's position. The SDT re-wrote Requirement R7 and its accompanying Measure and VSL to accommodate these concerns and provide additional clarity as to the SDT's intent.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7.

R7 VSL	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or Transmission Operator's evidence does not demonstrate that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	We agree with the approach. We recommend that the term "data center" be defined. How will the independence of any single data center be evaluated? This is almost impossible to prove. What type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.

Organization	Yes or No	Question 4 Comment
Hydro-Québec TransEnergie (HQT)	No	We agree with the approach. We recommend that the term "data center" be defined. How will the independence of any single data center be evaluated? This is almost impossible to prove. What type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.
Northeast Utilities	Yes	We agree with the approach. We recommend that the term "data center" be defined. How will the independence of any single data center be evaluated? This is almost impossible to prove. What type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.
ISO New England Inc.	No	We agree with the approach. We recommend that the term "data center" be defined. How will the independence of any single data center be evaluated? This is almost impossible to prove. What type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.
New York Independent System Operator	No	We agree with the approach, however we believe the term "data center" needs to be defined for this standard. How will the independence of any single data center be evaluated? This is almost impossible to prove. It is not clear what type of dated evidence (see M7) will be required to be compliant to this requirement? Also, M7 use "any common facility" while R7 use "any single data center"; for consistency, the same term should be used.

Response: The SDT has rewritten Requirement R7 in order to remove the term “data center”. The rewritten requirement focuses on the functionality required to maintain reliability and compliance rather than configuration. For entities that currently employ a single data center under their control, a level of redundancy of that data center will be required by the new requirement. Measure M7 has been rewritten with consistent language.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards.

Organization	Yes or No	Question 4 Comment
M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7.		
Ameren Services	No	R7 is redundant of R1 and should be removed. If a facility becomes "inoperable", and the entitity has another facility capable of operating and meeting the NERC compliance standards, then it would be independent.
Southern Company Transmission	No	The language should be more specific in indicating that an event that could make the primary center inoperable should not make the backup functionality inoperable. We suggest adding language in R1 that addresses mitigation of single points of failure and, therefore, eliminate R7.
SERC OC Standards Review	No	The language should be more specific in indicating that an event that could make the primary center inoperable should not make the backup functionality inoperable. We suggest adding language in R1 that addresses mitigation of single points of failure and, therefore, eliminate R7.
E.ON U.S.	No	R7 - Rather than a spearate requirement R. 7, the drafting team should consider adding language to R1 that specifies required redundancy.
Xcel Energy	Yes	However, this seems misplaced. possibly move in R1?
Response: The SDT believes that Requirement R7 is a standalone requirement, so as not to be confused as part of the plan required by Requirement R1. Requirement R7 has been rewritten to insure that primary and backup functionality are independent of each other. **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards.		
Midwest ISO Standards Collaborators	No	We agree with the drafting team's intent. However, we believe this requirement should be a sub-requirement of R1. Also, the VSL associated with Requirement 7 violates the Commission established VSL guideline that a VSL can't add to the requirement. Instead of using the data center as the requirement does, the VSL uses common facility. Facility could be construed to mean any communication equipment outside of the control centers and data center and ultimately out of the control of the registered entity if they rely on third party communications.
Response: The SDT believes that Requirement R7 is a standalone requirement, so as not to be confused as part of the plan required by Requirement R1. The VSL has been rewritten to be consistent with the rewritten Requirement R7. **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the		

Organization	Yes or No	Question 4 Comment
functionality required to maintain compliance with Reliability Standards.		

R7 VSL	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or Transmission Operator's evidence does not demonstrate that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards.

Organization	Yes or No	Question 4 Comment
South Carolina Electric & Gas Company	No	See my suggested version of the standard.
Response: Please see response in question 5 where the suggestions were spelled out.		
San Diego Gas and Electric Co	No	We agree with the change in principle, but there is different language in requirement R7 vs. the measure M7. The requirement states "Each other or any single data center" and the measure states "Each other or any common facility", which has a different meaning to us. Our preference would be for both sentences to use the "common facility" language.

Response: Requirement R7, Measure M7, and the associated VSL have all been rewritten with consistency in terminology between the 3.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7.

R7 VSL	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or Transmission Operator's evidence does not demonstrate that its primary and backup capabilities can

Organization	Yes or No	Question 4 Comment
		independently maintain the functionality required to maintain compliance with Reliability Standards.
Exelon	No	We agree with what we believe is the drafting team's intent. However, the current wording is ambiguous and is subject to inconsistent interpretation and application. Therefore the suggest the wording for R7 being changed to:Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and back-up facilities that can independently maintain the functionality, data availability and communications needed to maintain compliance with Reliability Standards.
Response: The SDT has employed your suggestion with modifications in rewriting Requirement R7. **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards.		
FMPA and its ARP Participants Listed as Follows: City of Vero Beach; Kissimmee Utility Authority; and Beaches Energy Services	No	As written, the requirement R7 (and M7) could be interpreted as requiring redundant Remote Terminal Units (RTUs) at substations and associated communcations. The wording of the requirement should be made to define more accurately what primary and backup capabilities are, and that they do not include the RTUs or communication from the RTUs.
Response: The SDT agrees that Requirement R7 should not require an additional level of redundancy to RTUs or the associated communications. Requirement R7 has been rewritten to focus on the functionality required to maintain reliability and compliance and does not require that level of redundancy. **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards		
Puget Sound Energy	No	R7 indicates "does not depend on each other or any single data center". M7 changes the words of "any single data center" to " any common facility". The difference in these terms and how they could be interpreted is significant. The SDT should revise M7 to match R7 at a minimum. The term "common facility" could be extremely interpreted to require duplicative RTU sensors at all substations and communications systems transmitting the information to isolate the primary and the backup control centers from any dependancy. Also it would be helpful to clarify whether "depend on each other" or "common facility" includes the building the centers reside in. In previous comments, the SDT responded that "the intent (of R7) is that if the primary control center is destroyed, the backup facility will be capable of collecting the data needed to support the reliable operation of the BES.". This response could imply the centers must reside in separate buildings or at

Organization	Yes or No	Question 4 Comment
		some significant distance from each other to prevent both locations from being impacted by a natural disaster. The SDT should explicitly list the components that the backup control center should not be dependent on.
Response: Requirement R7 has been modified and Measure M7 has been changed to match that modification. The SDT agrees that Requirement R7 should not require an additional level of redundancy to RTUs or the associated communications. Requirement R7 has been rewritten to focus on the functionality required to maintain reliability and compliance and does not require that level of redundancy. The SDT does not believe that listing the components would be able to cover all the different configurations of communications and facilities that exist, and believes that the focus on functionality and reliability requirements meets the need without being overly specific. **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards. **M7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7.		
Duke Energy	No	This requirement raises complex issues of redundancy that go beyond the need to provide backup functionality.
Response: The SDT is in agreement with this statement and has rewritten Requirement R7 to attempt to address these issues without being overly specific. **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards.		
ITC	Yes	Suggest removing the phrase "that depend on the primarycontrol functionality." from the end of R7 as it is unnecessary. R7 references a "single data center" while the VSL matrix for R7 references "common facility". Common facility is much broader than data center.
Response: Requirement R7 has been modified and Measure M7 has been changed to match that modification. **R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards. **M7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7.		
American Transmission Company	Yes	However, the sentence is long and could be broken up into two sentences. The phrase in blue at the end of the requirement does not add value and could be removed, "?that depend on the primary control functionality".

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	Yes	We agree with the clarifying language, but hold the opinion that the last part of the requirement "that depend on the primary control functionality" is unnecessary. The responsible entity must comply with all reliability standards under either the primary functionality or backup capability condition, hence the need for the backup functionality.
Ontario IESO	Yes	We agree with the clarifying language, but hold the opinion that the last part of the requirement "that depend on the primary control functionality" is unnecessary. The responsible entity must comply with all reliability standards under either the primary functionality or backup capability condition, hence the need for the backup functionality.

Response: Requirement R7 has been modified and that phrase has been removed.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards.

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	Yes	May be OK: Uncertainty due to the phrase "or any single data center". Not sure what that means. In data retention and VSL sections it refers to it as a common FACILITY.

Response: That phrase has been removed from Requirement R7 and the VSL has been changed to match that modification.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards

R7 VSL	N/A	N/A	N/A	The Reliability Coordinator, Balancing Authority, or Transmission Operator's evidence does not demonstrate that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards.

Organization	Yes or No	Question 4 Comment
FirstEnergy	Yes	Although we agree with R7, it should be clear that this requirement cannot be met during the time period when the primary or back-up functionality is lost for more than six months as provided by R9. We ask that this be

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>clarified by adding the wording "except as permitted by R9" at the end of Requirement R7.

Also, we would like confirmation from the SDT that R7 is not describing an "N-2" contingency. To alleviate any confusion, we suggest a slight change in wording to R7 as follows: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other, and that do not depend on any single data center for any functionality required to maintain compliance with Reliability Standards that depend on the primary control functionality."

We are not clear on the need for the phrase "that depend on the primary control functionality" in R7. It is ambiguous and seems unnecessary, so we ask the SDT to explain the need for this phrase.</td></tr>
<tr><td colspan="3">Response: It is not the SDTs intent for entities to require more than one backup location, through contract or its own facility, to provide backup functionality. Requirement R7 has been modified to clarify the redundancy requirements.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards</td></tr>
<tr><td>Dominion Virginia Power</td><td>Yes</td><td>The SDT should be aware of the concerns about NERCnet and the ISN that have been discussed by the Reliability Coordinator Working Group. If the loss of "any single data center" at a service provider facility can result in the ISN data being unavailable, is this a potential compliance issue?

The measure M7 refers to "any common facility" instead of to "any single data center". The requirement and the measure should use the same terms.</td></tr>
<tr><td colspan="3">Response: The SDT believes that any loss of data or control that would affect reliable operations of the grid and violate Reliability Standards could be a compliance issue. If an entity relies on the ISN and/or NERCnet for its operation it needs to have a means to ensure reliable operations should that function fail.

The term data center has been removed from Requirement R7 and the measure and requirement will use the same terms.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R7.</td></tr>
<tr><td>KCP&L</td><td>Yes</td><td></td></tr>
<tr><td>Pepco Holdings, Inc - Affiliates</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 4 Comment
MRO NERC Standards Review Subcommittee	Yes	
Tucson Electric Power	Yes	
PJM's NERC & Regional Coordination Department	Yes	
BCTC	Yes	
Oncor Electric Delivery	Yes	
PacifiCorp	Yes	
American Electric Power (AEP)	Yes	
Progress Energy	Yes	
ReliabilityFirst Corporation	Yes	
Entergy Services, Inc	Yes	
Response: Thank you for your response.		

5. **Do you believe this standard is ready for balloting? If not, please supply the specific reasons for your position.**

Summary Consideration: While there were many comments for this question, the SDT found few changes to be required. The following requirements were changed due to industry comments:

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards

Part 8.1 under R8: The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	Once "data center" is clearly defined, we believe the standard will be ready for balloting. For lack of a general comments question, would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be used consistently throughout the Standards.
Hydro-Québec TransEnergie (HQT)	No	Once "data center" is clearly defined, we believe the standard will be ready for balloting. For lack of a general comments question, we would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be be consistently used throughout the Standards.
Northeast Utilities	No	Once "data center" is clearly defined, we believe the standard will be ready for balloting.

Organization	Yes or No	Question 5 Comment
		For lack of a general comments question, would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be be consistently used throughout the Standards.
ISO New England Inc.	No	Once "data center" is clearly defined, we believe the standard will be ready for balloting. For lack of a general comments question, would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be be consistently used throughout the Standards.
New York Independent System Operator	No	Once "data center" is clearly defined, we believe the standard will be ready for balloting.For lack of a general comments question, would like to propose here the following change: in R1.5 and R8.1 the terms " to fully implement the backup functionality" should be replaced by "to fully implement the backup functionality elements identified in Requirement R1.2". Regional Entity has been replaced with Reliability Assurer to reflect what is proposed in Version 4 of the Functional Model. The terms Regional Entity, and Regional Reliability Organization are used throughout the NERC Standards. One term should be be consistently used throughout the Standards.
Response: 1. See response to question 4. 2. R1.5 & R8.1: The SDT doesn't see where the suggested change adds clarity to the requirement. You need to look at the standard as a whole. For example, Requirements R4 & R5 also discuss required functionality. Requirement R1.2 merely addresses the high level elements needed in the written plan. No change made. 3. The standards are being changed to reflect consistent terminology as the different projects come across the terms in question.		
Ameren Services	No	R1: Delete the word "current", it is not defined and adds nothing. R1: "backup functionality" should be restored to "backup capability" R1.1: "functionality" should be replaced with "facility" and "for a prolonged period of time" defined. This may be

Organization	Yes or No	Question 5 Comment
		the period of time it would take to completely replace the facility that became inoperable. R3: Agree that it should be removed as mentioned in Question 1, above. R4 and R5:In addition to the consideration of the comments in question 3, above; R4 should be clear that an RC's backup control center, that happens to be another entity's control center, does not depend on their primary control center. Likewise R5 should be clear that an BA/TOP backup control center, that happens to be provided through contracted services, does not depent on their primary control center R4.1, R4.2, R5.1, and R5.2 are exceptions and if they remain should be clearly stated as such. No subrequirements should be worded, such that on their own they could be mis-interpeted. R6.1 Only changes pertinent to the implementation of the operating plan should be required within the time frame specified. R7: As noted above in question # 4, R7 is redundant of R1 and should be removed. If a facility becomes "inoperable", and the entitity has another facility capable of operating and meeting the NERC compliance standards, then it would be independent. R8: Define "annual"; is it a calander year or something else. Under the effective date section of this standard, clearly state when the first test needs to be completed. R8.1 Add "simulated" in front of "loss of primary control" M1: Is there a significance in the words "current, in force Operating Plan"? Is not "current" and "in force" the same? If not, please explain. M2: Is there a significance in the words "current, in force Operating Plan"? Is not "current" and "in force" the same? If not, please explain. M6: Is there a significance in the words "current, in force Operating Plan"? Is not "current" and "in force" the same? If not, please explain.

Response: R1: The SDT does not feel a need to remove the word “current”. The word “current” has been used to infer that the Operating Plan is to be the most recent version.   No change made.

R1: The SDT feels that “functionality” describes the intent of the requirement. It denotes the essentials needed to support the backup. No change made.

R1.1: Because a backup facility is not required for the Balancing Authority and Transmission Operator, the word “functionality” will not be changed. The Balancing Authority and Transmission Operator can obtain backup functionality by contract.

“Prolonged period of time” is the term used by FERC in Order 693 to mean the time to replace the primary control center functionality. Order 693 states “be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center”.

Organization	Yes or No	Question 5 Comment
R3: See answer to question 1. R4 & R5: The intent is that backup control centers or backup capabilities should not depend on the primary control center that has been evacuated. The SDT believes that the requirement as written addresses this concern. No change made. R4.1, R4.2, R5.1, R5.2: These have been changed to bullets. R6.1: Any changes to the Operating Plan, whether they are plans, processes, procedures or implementation, need to be included in the update. Pertinent is too flexible and open-ended and impossible to measure. No change made. R7: See response to Question 4. R8: “Annual” means once in a calendar year as per Webster’s. No change made. Tests should be performed within one year of implementation. R8.1: The word “simulated” has been added. Part 8.1 under R8: The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality. M1, M2, and M6: The current Operating Plan is the one that should be “in force”.		
KCP&L	No	The term "Reliability Assurer" referred to in R9, and throughout the proposed Standard, is not a defined term. Recommend the SDT either propose a definition for this term and for the definition to be placed in the NERC Glossary of Terms or use a term that is defined and serves its applicable purpose in R9. It is not clear from requirement R8 or its sub-requirements that training of personnel who are to execute back-up plans are trained in the plans. Recommend the SDT consider including some personnel training requirements. The VSL's for R3 include the phrase, "that is depended upon for compliance with one or more Requirements in the Reliability Standards having a [Lower, Medium, High] VRF". This is problematic in the VSL as it can be debatable as to what requirements out of all the Reliability Standards apply here. Recommend NERC Staff and/or the SDT remove this phrase from the R3 VSL's. Also recommend NERC Staff and/or the SDT consider modifying the VSL's for R3 to reflect not ensuring back-up capability through others with one facility as Lower VSL, two facilities as Moderate, three facilties as High, and four or more as Severe. The VSL's for R4 and R5 include the phrase, "one or more of the Requirements in the Reliability Standards applicable to [the Reliabiliity Coordinator, a Balancing Authority and Transmission Operator respectively] that depend on the primary control center functionality and which have a [Lower, Medium, High] VRF." This is problematic in the VSL as it is debatable as to what requirements out of all the Relaibility Standards apply here. Recommend NERC Staff and/or the SDT consider removing this langauge and replace with language that is measurable and definitive.

Organization	Yes or No	Question 5 Comment
		Recommend moving the following langauge from the Lower VSL for R6 to the Medium VSL on the basis of it is more of a concern to have updated a plan that needed updating after a year and less of a concern to have updated a plan that needed updating after 60 days but less than a year. The suggested language move is: "The Reliability Coordinator, Balancing Authority, or applicable Transmission Operator, has evidence that it's dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in one calendar year."
Response: Regional Entity is the correct term and the standard has been corrected. Training requirements are dealt with in the PER standards. The SDT believes that this language is quite clear and non-problematic in that applicability of a standard or requirement is clear and the accompanying VRF is clearly stated. The VSL as written covers the situation adequately. No change made. The SDT believes that this language is quite clear and non-problematic in that applicability of a standard or requirement is clear and the accompanying VRF is clearly stated. No change made. The SDT believes that the VSL is correct with the use of 'or' to differentiate the 2 different conditions and that Lower is the appropriate location for the first occurrence. No change made.		
Southern Company Transmission	No	We have the following comments regarding the noted requirements of this standard:R1: The word, "current", should be removed from the language of the requirement. R1: What is the difference between "operability" and "functionality"? Are they the same? R1.1: Delete "for a prolonged period of time." R1.3: What does "consistent" mean? does it mean "adequate to meet compliance"? 1.6.2: This requirement appears to be redundsant to R1.6. R2: The word, "current", should be removed from the language of the requirement. R4: In the first sentence, change "facility" to "functionality" and delete all remaining language of the sentence following "functionality. R5: In the first sentence, delete all remaining language of the sentence following "functionality". R6.1: We suggest that changes that are necessary for the operator to implement the back-up plan should be updated within 60 days - all other changes shall be addressed during the annual review. R8: When does the first test have to be performed, following implementation, to be compliant? - one day or

Organization	Yes or No	Question 5 Comment
		within one year after implementation? We request that "annual" be replaced with "a calendar year". R8.1: We suggest adding the word "simulated' in front of "loss of primary control". General Comment: Measures and VSLs should use the same words and be consistent with the requirements of the Standard.
SERC OC Standards Review	No	We have the following comments regarding the noted requirements of this standard:R1: The word, “current”, should be removed from the language of the requirement. R1: What is the difference between “operability” ?and functionality? Are they the same? R1.1: Delete "for a prolonged period of time." R1.3: What does “consistent” mean? does it mean "adequate to meet compliance"? 1.6.2: This requirement appears to be redundsant to R1.6. R2: The word, “current”, should be removed from the language of the requirement. R4: In the first sentence, change "facility" to "functionality" and delete all remaining language of the sentence following "functionality. R5: In the first sentence, delete all remaining language of the sentence following "functionality". R6.1: We suggest that changes that are necessary for the operator to implement the back-up plan should be updated within 60 days - all other changes shall be addressed during the annual review. R8: When does the first test have to be performed, following implementation, to be compliant? - one day or within one year after implementation? We request that "annual" be replaced with "a calendar year". R8.1: We suggest adding the word "simulated' in front of "loss of primary control". General Comment: Measures and VSLs should use the same words and be consistent with the requirements of the Standard.

Response: The SDT does not feel a need to remove the word “current”. The word “current” has been used to infer that the Operating Plan is to be the most recent version. No change made.

R1: The primary control center becoming inoperable means that the control center is unable to process the functions needed to support grid operations. No change made.

R1.1: “Prolonged period of time” is the term used by FERC in Order 693 to mean the time to replace the primary control center capability. Order 693 states “be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center”. No change made.

Organization	Yes or No	Question 5 Comment
R1.3: "Consistent" is a word used by FERC in Order 693. Order 693 states: "provides that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk-Power System". No change made. R1.6.2: The commenter has not provided a reason for assuming that Requirements R1.6 and R1.6.2 are redundant. The SDT believes the requirements are not redundant. No change made. R2: The SDT does not feel a need to remove the word "current". The word "current" has been used to infer that the Operating Plan is to be the most recent version. No change made. R4: As per Order 693, the RC needs to have a backup facility and not just backup functionality. No change made. R5: The commenter has not provided the rational for making the deletion. The SDT has decided not to delete the words suggested. R6.1: Any changes to the Operating Plan, whether they are plans, processes, procedures or implementation, need to be included in the update. No change made. R8: "Annual" means once in a calendar year as per Webster's. No change made. The first test of the operating plan must be completed within one year of the effective date of the standard. R8.1: The word "simulated" has been added. Part 8.1 under R8: The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.		
Bonneville Power Administration	No	It has potential, but not sure about possible planned construction outage time duration.
Response: The commenter has not indicated when the planned construction outage is to occur so the SDT is unable to provide a response.		
Midwest ISO Standards Collaborators	No	There is significant clean up identified in this standard. A fourth comment period should be pursued to verify that the drafting team has addressed concerns appropriately. Additionally, we offer these comments. We suggest it is possible to create four VSLs for requirement 9 based on the number of months the plan is late. FERC established in their June 2008 VSL order that their preference is to create a VSL for every level if possible. This is clearly possible based on our suggestion.
Response: The SDT does not feel that any significant changes have been made to the third revision and does not see the necessity for a 4th posting. R9 VSL: The SDT feels that the VSLs identified satisfy FERCs intent.		
FirstEnergy	No	We ask that our comments provided above have been appropriately considered before balloting begins. Also, we provide the following comments:In Requirement R9, the SDT changed the term "Regional Entity" to "Reliability Assurer". "Reliability Assurer" is a new term used in Version 4 of the NERC Functional Model but it

Organization	Yes or No	Question 5 Comment
		is not clear if Version 4 is the latest approved Model. From looking at the NERC website, it only appears as though Version 3 is approved. We ask the SDT to confirm. Furthermore, if Version 4 is approved and Reliability Assurer is, in fact, an approved term, we believe the standard would be much clearer if Regional Entity was still used because it is much more familiar to industry at this point in time since Version 4 of the Functional Model is new. If still desired to be used, the SDT can put Reliability Assurer in parenthesis immediately following Regional Entity, i.e. "Regional Entity (Reliability Assurer)"
Response: Please see the responses to comments in previous questions to determine if your comments have been adequately addressed. Regional Entity is the correct term and the standard has been corrected.		
MRO NERC Standards Review Subcommittee	No	R1, Requires the entity to "have a current Operating Plan". NERC defines Operating Plan as "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and OperatingProcesses. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicatingrestoration progress with other entities, etc., is an example of an Operating Plan". Contained in the defined term, NERC explains that an Operating Procedure and Operating Process are sub-components within the Operating Plan. R1.3 and R1.6 dictate the use of an Operating Process. R1.4 dictates the use of an Operating Procedure. This will lead to confusion within the industry. Recommend the SDT streamline these requires since they are sub-components of an Operating Plan.R1, R4, R5 and R7, Request clarification, The Operating Plan described in R1 is to contain items for "backup functionality" and at a minimum contain the sub-requirements in R1.2. Then in R4 (and in R5 for the BA and TOP), the SDT requires the RC to "have a backup control center facility that provides the functionality required for maintaining compliance with ALL Reliability Standards that depend on primary control center functionality". The PURPOSE of this Standard is for continued reliability operations of the BES (also stated in R1, and R3). FERC Order 693 states in paragraph 672, under (3) "provide for a minimum functionality to replicate the critical reliability functions of the primary control center". Note: same paragraph (5) states: "includes a Requirement that all reliability coordinators have full backup control centers". Does this proposed Standard apply to the Reliability of the BES or all Standards assigned to a RC, TOP, and BA, please clarify. R1.5, States that an entity has up to 2 hours to fully implement the backup functionality. Where did the two hour time frame come from and what is the justification for it? There are some examples in actual emergencies that indicates the backup control center should be a substantial distance from the primary, to prevent the possibility of losing both the primary and backup facilities to the emergency, which may make it impossible to have the backup up, running, and fully functional within 2 hours. Please note the hurricanes in New Orleans, floods in Iowa. R5, The SDT is adding more components to the non-defined term of "backup functionality" as stated in the

Organization	Yes or No	Question 5 Comment
		sub-requirements of R1.2. Added are the processes of "monitoring, control, logging, and alarming". If these are components of R1.2.1, then they should be added to R1.2.1, which will stream line the Standard. R2, The MRO NSRS does not believe that it is necessary for an unmanned facility (like a repeater tower) that "supports" the backup facility to have a copy of the Operating Plan and suggests the requirement be modified to clarify. R7 and R9, please clarify what backup "capability" is when the rest of the proposed standard references backup "functionality". R9, Uses the term Reliability Assurer and is undefined as stated by NERCs Reliability Functional Model (V4) "While the specific role of the Reliability Assurer is not fully developed at the present time, the following are representative of the Tasks that might be performed:". The term Regional Entity or Reliability Coordinator should be used since they are defined and should be contained in R9. If at a later date Reliability Assurer is approved, NERC may submit an errata to update the Requirement.
Response: R1: The SDT has reviewed the NERC Glossary definitions and believes that the terms have been used correctly. No changes made. The standard applies to the reliability of the BES which is achieved through the compliance to standards. R1.5: The SDT has discussed the rationale for the transition to the backup functionality in the case of failure of the primary control center in previous comments. No change made. R5: Requirement R1.2 addresses the elements required to support functionality. The SDT does not believe that a change is needed. R2: A change has been made for clarity. **R2**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. R7: Using the term "functionality" instead of capability in Requirement R7 would be problematic as the Reliability Coordinator can't have backup "functionality" since they are required to have "a backup control center facility" per Requirement R4. Backup capabilities seems to be the right term to describe what the SDT is requiring in the standard. The same issue applies in Requirement R9 since it is also describing Reliability Coordinator's and Transmission Operator's/Balancing Authority's. No change made. R9. Regional Entity is the correct term and the standard has been corrected.		
IRC Standards Review Committee	No	Whether or not the standard is ready for ballot will depend on the extent to which the above comments are addressed. Further, the following comments also need to be addressed:VSLs for R2: The Severe condition is "The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup

Organization	Yes or No	Question 5 Comment
		functionality but no version of the plan is available at all of its control locations." There is no mention of having no version at one of the primary and backup control locations. If one version is missing, what VSL is assigned? VSLs for R3: VSL measures the extent to which an entity fails a requirement, not how impactive the failure is. However, the VSLs for R3 are assigned according to what level of VRFs the requirements have failed. Factoring the impact of a failure in the determination of the extent of failure is improper. These need to be revised. VSLs for R4: Similar comments as for VSLs for R3. Further, please note our comments and suggestions under Q3. If R4 is to be revised, the VSLs (and Measure) will need to be revised accordingly. VSLs for R5: Same comments as for VSLs for R4. We are particularly concerned with the determination of VSL based on VRFs for R3, R4 and R5. This is improper in applying the fundamental concept of VRF and VSL. We feel that the standard is not ready for balloting until these VSLs are revised to remove the VRF component.
Ontario IESO	No	Whether or not the standard is ready for ballot will depend on the extent to which the above comments are addressed. Further, the following comments also need to be addressed: VSLs for R2: The Severe condition is "The Reliability Coordinator, Balancing Authority, or Transmission Operator has an Operating Plan for backup functionality but no version of the plan is available at all of its control locations." There is no mention of having no version at one of the primary and backup control locations. If one version is missing, what VSL is assigned? VSLs for R3: VSL measures the extent to which an entity fails a requirement, not how impactive the failure is. However, the VSLs for R3 are assigned according to what level of VRFs the requirements have failed. Factoring the impact of a failure in the determination of the extent of failure is improper. These need to be revised. VSLs for R4: Similar comments as for VSLs for R3. Further, please note our comments and suggestions under Q3. If R4 is to be revised, the VSLs (and Measure) will need to be revised accordingly. VSLs for R5: Same comments as for VSLs for R4. We are particularly concerned with the determination of VSL based on VRFs for R3, R4 and R5. This is improper in applying the fundamental concept of VRF and VSL. We feel that the standard is not ready for balloting until these VSLs are revised to remove the VRF component.

Organization	Yes or No	Question 5 Comment
Response: Please see the responses to comments in previous questions to determine if your comments have been adequately addressed. R2: The SDT believes that it is a severe violation regardless of whether the plan is missing at one or more locations. No change made. R3, R4, & R5: The SDT believes that the technique employed is within FERC guidelines and is an acceptable method of quantifying the issue.		
PJM's NERC & Regional Coordination Department	No	Numerous requirements need to be rewritten for clarification and subsequently, VSLs will need to be rewritten followed by another posting prior to this standard being ready for balloting. In addition, there are still some areas which should be cleaned up:R1 - the term current should be ommitted as it adds a new term which should simply be covered by R6. R1.2.5 - does this refer to CIP 003 - CIP 009, or some other cyber security requirements?
Response: The SDT does not feel that any significant changes have been made to the third revision and does not see the necessity for a 4th posting. R1: The SDT does not feel a need to remove the word "current". The word "current" has been used to infer that the Operating Plan is to be the most recent version. No change made. R1.2.5: This requirement identifies the need to address how Cyber and Physical security will be maintained for the backup functionality. The Cyber and Physical security requirements are identified in the CIP standards.		
Dominion Virginia Power	No	1) See response to question 3. 2) Requirement R9 allows 6 months after an unplanned outage before a plan is needed for restoration of the primary or backup capability. This is too long. A plan should be required within two weeks even if it is only a preliminary plan. The plan should be updated at least monthly thereafter until the restoration is complete.
Response: 1. See response to question 3. 2. The SDT has reviewed the 6 month time frame for developing the plan and believes that it is an appropriate time frame. No change made.		
South Carolina Electric & Gas Company	No	See my suggested version of standard. R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of their most recently approved Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its control center becomes inoperable. This Operating Plan for backup functionality shall be available in its primary control center and at the location supporting backup functionality. The Operating Plan shall include the following:

Organization	Yes or No	Question 5 Comment
		R1.1. Operating Procedures that stipulate: R1.1.1 Who has the decision-making authority for determining when to implement the Operating Plan. R1.1.2 The actions required to transition from loss of primary control center functionality to backup control functionality. R1.1.3 The actions required during the transition period. R1.1.4 The estimated transition time to fully implement the backup functionality which must be attained in less than or equal to two hours. R1.1.5 The list of all entities to notify when a change of operating locations or functionality is required. R1.1.6 The roles for personnel involved during the initiation and implementation of the Operating Plan. R1.2. A summary description of the elements required to support the backup functionality. These elements shall include: R1.2.1. Tools and applications that allow visualization capabilities to ensure operating personnel maintain situational awareness of the BES. R1.2.2. Data communications. R1.2.3. Voice communications. R1.2.4. Power source(s). R1.2.5. Physical and cyber security. R1.3. A description of the methods used for keeping the backup functionality compatible with the primary control center functionality. R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall annually review and approve its Operating Plan for backup functionality R2.1. An Operating Plan shall be updated and approved within sixty calendar days of any changes described in Requirement R1. R3 (Deleted) R4. See Question 3. R5. See Question 3. R6. (Now R2)

Organization	Yes or No	Question 5 Comment
		R7. Incorporated into R1. R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct a test of its Operating Plan once each calendar year and document the results. The results should state: R8.1 The transition time from loss of primary control center functionality to full backup control functionality. R8.2 The length of time the backup functionality was utilized to operate the BES. A minimum of two continuous hours is required. R9. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability, and anticipates that loss will last for more than six calendar months shall provide a plan to its Reliability Assurer within six calendar months of the date the functionality was lost, detailing how it will re-establish backup capability.
Response: The SDT believes that the existing requirements for the proposed standard are appropriate and necessary and that additional clarity would not be achieved at this time due to the suggested changes. No changes made.		
San Diego Gas and Electric Co	No	We have a few issues related to the language in the revised standard that we feel need to be addressed:R1.1 - the phrase "prolonged period of time" needs to be defined more clearly. One person could interpret that phrase to mean 3 months, while another person might think anything over 1 week is prolonged. R3 - "Transmission Operator directing BES operations through other entities"...We would suggest replacing the word "entities" with something else, such as parties or organizations. We feel that "entities" is too closely related to the registration process. What if the party in question is not a registered entity? It gets confusing. R6.1 - We would suggest adding the word "substantial" so that the second line reads "shall take place within sixty calendar days of any substantial changes". Other wording that is more precise is also welcome, but we wanted it to be clear that an update of the plan is not necessary for more trivial changes that happen several times per month at the control centers. R9 - We don't understand who the "Reliability Assurer" is. We actually liked the previous "Regional Entity" wording.Thanks very much,Randy SchimkaSDG&E
Response: R1.1: "Prolonged period of time" is the term used by FERC in Order 693 to mean the time to replace the primary control center capability. Order 693 states "be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center". No change made. R3: The SDT believes that the word "entities" is appropriate. No change made. R6.1: The requirement was changed for the 3rd posting to reflect that only those changes that impact Requirement R1 need to be approved within 60 days. The SDT believes that this is appropriate. No change made.		

Organization	Yes or No	Question 5 Comment
R9. Regional Entity is the correct term and the standard has been corrected.		
Exelon	No	There are significant opportunities for rewording requiremnts in this revision, for example the ambiguous wording in R7 requires a fourth comment period.
Response: The SDT cannot appropriately respond without specific concerns/suggestions. However, the SDT does not feel that any significant changes have been made to the third revision and does not see the necessity for a 4th posting**.**		
Xcel Energy	No	We agree with the intent of the standards but would like the items mentioned in our comments addressed prior to balloting.R1.1 "prolonged" is a subjective term and will need to be changed or defined in order to have a standard that minimizes interpretation. R1.3 "consistent" is a subjective term and will need to be changed or defined in order to have a standard that minimizes interpretation.
Response: R1.1: "Prolonged period of time" is the term used by FERC in Order 693 to mean the time to replace the primary control center capability. Order 693 states "be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center". No change made. R1.3: "Consistent" is a word used by FERC in Order 693. Order 693 states: "provides that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk-Power System". No change made.		
E.ON U.S.	No	R1.6.2 appears redundant with R1.6 which requires a description of the actions to be taken during the transition. The phrase "manage the risk" is vague and subject to differing interpretations by organizations and auditors. R1.6.2 also describes outages of primary or backup functionality which can be different from a "loss of primary control center" used in R1.6. Requirement R. 8 requires "an annual test of its Operating Plan that demonstrates: the transition time?". R8 introduces additional reliability risk for the BES by requiring RC/BA/TOPs to annually remove from service their primary control center, relocate staff, and then re-intialize all systems. This standard should allow for simulated exercises rather than actual test, similar to requirements in EOP-005. Annual test should be defined as a test each "calendar year".
Response: R1.6.2 adds clarification that the plan includes actions for when the primary or backup functionality is "out" for planned circumstances (as opposed to the unplanned loss of the primary control center). The risk for each entity will be different depending on circumstances and the plan. The plan should identify how each entity will respond to any risks associated with their particular situation. No change made.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">R8: The requirement does not require that the primary control center be “removed from service”. The word ‘simulated’ has been added for clarity to Part 8.1.

Part 1 under R8: The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.</td></tr>
<tr><td>PacifiCorp</td><td>No</td><td>R9 is ambiguous and requires clarification prior to balloting. It is unclear whether R9 requires that the responsible entity must submit a plan within six months showing how it will re-establish backup capability or whether it requires the responsible entity to completely re-establish backup capability within six months. This is a very critical distinction.

In addition, R9 contains the term "Reliability Assurer" which is not a NERC defined term. It is unclear to what entity this term is referring. This must be clarified before the Standard is ready for balloting.</td></tr>
<tr><td colspan="3">Response: R9: The SDT believes that the requirement states that a plan be submitted to its Regional Entity within 6 months. The actual time frame required to re-establish the primary control center should be defined in the plan. No change made.

R9: Regional Entity is the correct term and the standard has been corrected.</td></tr>
<tr><td>FMPA and its ARP Participants Listed as Follows: City of Vero Beach; Kissimmee Utility Authority; and Beaches Energy Services</td><td>No</td><td>See comments above.

We suggest: 1) removing the paranthetical from R5 and M5;

2) defining what "primary and backup capabilities" in R7 and M7 mean more specifically, and specifically excluding the need for redundant RTUs and associated communications;

3) Reliability Assurers (referred to in R9 and M9) ought to be a defined term, or we suggest staying with Regional Entity at this time until Reliability Assurers is a defined term in NERC's Glossary; and

4) although R1.2 only refers to physical and cyber security and does not refer to "Critical Assets" or "Critical Cyber Assets", it ought to be clear that just because there may be a backup control center, it does not automatically become a Critical Asset or Critical Cyber Asset, especially if the primary control center is not a Critical Asset or Critical Cyber Asset</td></tr>
<tr><td colspan="3">Response: Please see responses above for previous comments.

1) The SDT believes that the parenthesis add clarity to the requirement. No change made.

2) Requirement R7 has been modified to clarify the redundancy requirements.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
3) Regional Entity is the correct term and the standard has been corrected. 4) The SDT believes that the determination of critical assets and therefore, critical cyber assets, is covered by a separate standard and should not be duplicated in this one.		
Progress Energy	No	Effective Date: Include when the first test of the Operating Plan (R8) has to be performed. Is it (a) before the effective date, (b) within the same calendar year as the effective date, or (c) within 1 year of the effective date? To be consistent with the once per calendar year recurring requirement, we suggest option (b). R1.3: The term “consistent” can have too many interpretations - it could be interpreted that the backup tools must be exactly the same as the primary, which should not be required. If this statement was intended as a reminder to keep Operator tools similar at the backup, then make this a "should" statement instead of a "shall." Another option would be to reword it to say "for keeping the backup functionality adequate to meet compliance." R8: Suggest clarifying "annual" here and in all other applicable sections of the standard. Based upon the SDT's response to previous comments, we recommend using the phrase "once per calendar year"
Response: R8: The first test of the operating plan must be completed within one year of the effective date of the standard. R1.3: “Consistent” is a word used by FERC in Order 693. Order 693 states: “provides that the extent of the backup capability be consistent with the impact of the loss of the entity’s primary control center on the reliability of the Bulk-Power System”. No change made. R8: “Annual” means once in a calendar year as per Webster’s. No change made.		
ITC	No	In addition to changes suggested in Q4, we believe that VSL's for R7 should be developed for lower and medium/high.We suggest it is possible to create four VSLs for all requirements. FERC established in their June 2008 VSL order that their preference is to create a VSL for every level if possible.
Response: The SDT believes that the VSL’s are appropriate for each requirement. No change made.		
Duke Energy	No	In addition to the comments for Questions #3 and #4 above, this standard lacks sufficient clarity in the following areas to proceed to ballot: R1. Each Reliability Coordinator, Balancing Authority, and TransmissionOperator shall have a current (what does “current” mean?) Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center (some entities have concerns with premise of primary and secondary - they have dual “primary” centers so the notion of primary and secondary is problematic) becomes inoperable (what does “inoperable” mean ? should this be clarified to mean "loss of functionality"?).

Organization	Yes or No	Question 5 Comment
		R1.3. An Operating Process for keeping the backup functionality consistent (what does this mean ? does this mean exact duplicate functionality, does this mean every application, process, etc needs to be exactly consistent, what is the time dimension allowed for achieve consistency?) with the primary control center. R1.6. An Operating Process describing the actions to be taken during the transitionperiod between the loss of primary control center functionality and the time to fully implement the backup functionality elements identified in Requirement R1.2. The Operating Process shall include at a minimum: R1.6.1. A list of all entities (all is a very inclusive word ? suggest something like ?primary?) to notify when there is a change in operating locations. R1.6.2. Actions to manage the risk to the BES (what does this phrase mean? what is the risk to the BES associated with loss of a control center?) during the transition fromprimary to backup functionality as well as during outages of the primary or backup functionality. R1.7. Identification of the roles for personnel (is this by name or by function, i.e. Manager of the Control Center?) involved during the initiation and implementation of the Operating Plan for backup functionality. R3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. [Violation Risk Factor = Medium] [Time Horizon =Operations Planning] (This requirement is vague and subject to different interpretations. Suggest removing the entire requirement.) R4 and R5: See comment above on Question # 3. R6. Each Reliability Coordinator, Balancing Authority, and TransmissionOperator, shall annually review and approve its Operating Plan for backupfunctionality. [Violation Risk Factor = Lower] [Time Horizon = Operations Planning]R6.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1. (How significant of a change in capabilities requires a revised/approved update within 60 days?) R9. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months, shall provide a plan to its Reliability Assurer (who is this? This is apparently a new term defined in the next version of the Functional Model; since this new version is not yet approved, should it be used here?) within six calendar months of the date when the functionality is lost, showing how it will reestablish backup capability. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] After these clarifications are made, the measures need to be closely reviewed again to assure they are aligned with the words in the requirements. For instance, the measures should not introduce new requirements as several appear to do as currently written.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>Likewise the VSL matrix will need to be reviewed again for alignment with the requirements.</td></tr>
<tr><td colspan="3"> Response: R1: The word “current” has been used to infer that the Operating Plan is to be the most recent version. The standard does not discuss secondary control centers. Each entity will need to develop a plan that will meet the requirements of the standard. Inoperable would mean that the control center can no longer be used to ensure the reliable operation of the BES.
R1.3: “Consistent” is a word used by FERC in Order 693. Order 693 states: “provides that the extent of the backup capability be consistent with the impact of the loss of the entity’s primary control center on the reliability of the Bulk-Power System”. No change made.
R1.6: The SDT believes that each entity should determine the other entities that need to be contacted for this requirement and that the wording is appropriate. No change made.
R1.6.2: The SDT cannot determine every risk that might be faced with the loss of a primary control center; nor is it appropriate to try to determine and detail each risk in the standard. Each entity will need to develop a plan for the transition period from the loss of the primary control center to fully implement the backup functionality that ensures the reliable operations of the BES. The basic elements that support functionality are defined in Requirement R.1.2.
R1.7: By function.
R3: The SDT believes the requirement is necessary and clearly stated. For reference, see discussions in Question 1. No change made.
R4/R5: See answers on question #3.
R6: Only those changes that impact R1 need to be approved within 60 days.
R9. Regional Entity is the correct term and the standard has been corrected.
All measures and VSL’s have been reviewed to ensure that they are appropriate to the associated requirement. </td></tr>
<tr><td>Puget Sound Energy</td><td>No</td><td> Puget Sound Energy commented previously that the 24 month implementation timeline was not reasonable. The SDT responded that "The SDT agrees with the majority of commenters that 24 months is the correct timeframe for this standard." The questions/comments regarding the terms used in R7/M7 mentioned in response to question 4 could have significant impact on the ability for an enitity to meet within this timeframe. Until R7 is further clarified, the SDT should extend the implementation timeframe from 24 months to 36 months.
Also in accordance with FERC's "Order on Violation Severity Levels Proposed by the Electric Reliability Organization," issued June 19, 2008 (Docket No. RR08-4-000), FERC has stated its preference for graduated VSLs since the application of any penalty for a violation can be more consistently and fairly applied based on the degree of the violation. In light of this, NERC should revise the proposed VSLs to include graduated violation severity levels for each and every requirement. </td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Requirement R7 has been clarified; therefore, the SDT does not see any reason to change to the Implementation Plan.
R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards
The SDT believes that the VSL’s are appropriate for the requirements of the standard.</td></tr>
<tr><td>American Transmission Company</td><td>No</td><td>R9 uses the term Reliability Assurer which is not currently defined by NERC. It should be replaced with Regional Entity.
R7 and R9 use the term "backup capability". The rest of the requirements use the term "backup functionality". For consistency and clarity, it is recommended that one term is used consistently in all of the requirements.
The changes or deletion of R3 needs to be clarified. If R3 is kept, then the verbiage needs to be modified as stated above.
R2 should read "at the location which provides backup functionality", not "at the location supporting backup functionality". Many locations may support backup functionality, not all of which are manned and would need a copy of the plan. This re-write would remove the need for unmanned locations to have a copy of the Operating Plan.</td></tr>
<tr><td colspan="3">Response: R9. Regional Entity is the correct term and the standard has been corrected.
R7: Using the term “functionality” instead of capability in Requirement R7 would be problematic as the Reliability Coordinator can’t have backup “functionality” since they are required to have “a backup control center facility” per Requirement R4. Backup capabilities seem to be the right term to describe what the SDT is requiring in the standard. The same issue applies in Requirement R9 since it is also describing Reliability Coordinator’s and Transmission Operator’s/Balancing Authority’s. No change made.
R3: Please see the discussion for question 1. No change made.
R2: A change has been made as suggested.
R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality.</td></tr>
<tr><td>American Electric Power (AEP)</td><td>Yes</td><td>While ready for ballot, a couple other suggestions: (a) The term "Reliability Assurer" should be defined within the appliability of the standard. Is it typically the RC, NERC, or some other entity?
(b) R9 - What is the action that the Reliability Assurer to take when it receives the plan. If no action is required, the plan could be maintained by the RC, BA, or TO. We are not sure of what value is intended to be provided by the Reliability Assurer when the plan is received perhaps months after the loss of primary and/or back-up</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		capability. (c) R3, M3 - We are not sure that references to third party entities is necessary as the applicable entity is ultimately still responsible.
Response: a) Regional Entity is the correct term and the standard has been corrected. b) The standard does not require that the Regional Entity take any action with the plan. The intent is to have the entity that has lost its primary control center develop a plan for re-establishing full functionality. c) Please see the discussion for question 1.		
Entergy Services, Inc	Yes	We request the drafting team consider increasing the maximum transition time to 3 hours from 2 hour in R1.5. The cost of full implementation of backup functionality in 2 hours is significantly greater than implementation within 3 hours with little attendant increase of reliability resulting from the additional one hour.
Response: The SDT has discussed the rationale for the transition to the backup functionality in the case of failure of the primary control center in previous comments. No change made.		
Pepco Holdings, Inc - Affiliates	Yes	
Tucson Electric Power	Yes	
BCTC	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst Corporation	Yes	
Response: Thank you for your response.		

Implementation Plan for EOP-008-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

EOP-008-1 — Loss of Control Center Functionality

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards and no new or revised definitions in the proposed standard.

Compliance with Standard

EOP-008-1: Loss of Control Center Functionality	Functions That Must Comply With the Associated Requirements		
	Reliability Coordinator	Balancing Authority	Transmission Operator
R1	X	X	X
R2	X	X	X
R3	X	X	X
R4	X		
R5		X	X
R6	X	X	X
R7	X	X	X
R8	X	X	X
R9	X	X	X

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard.

Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with the requirements.

EOP-008-0 is retired when EOP-008-1 goes into effect.

All requirements of EOP-008-1 will go into effect the first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008
6. Third posting of revised standard on March 17, 2009

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q09. The current draft is the fourth iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit standard for balloting.	August 2009
2. Submit standard for recirculation balloting.	September 2009
3. Submit standard to BOT.	October 2009
4. Submit to regulatory authorities.	November 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.

Effective Date: The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for a prolonged period of time.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Voice communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1 part 1.2. The Operating Process shall include at a minimum:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the current year and three previous years in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.

- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the current year and three previous years, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Measurement M8.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's parts (1.1 through 1.6) or the plan does not reflect the date of its last issuance.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's parts (1.1 through 1.6) or is not compliant with Requirement R1, part 1.5.	The responsible entity did not have a current Operating Plan for backup functionality.
R2.	The responsible entity had an Operating Plan for backup functionality available at all of its control locations but at one location it was not the current plan.	The responsible entity had an Operating Plan for backup functionality available at all of its control locations but at all locations it was not the current plan.	N/A	The responsible entity had an Operating Plan for backup functionality but no version of the plan was available at all of its control locations.
R3.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator did not demonstrate that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R3.
R4.	The responsible entity has demonstrated that it has backup	The responsible entity has demonstrated that it has backup	The responsible entity has demonstrated that it has backup	The responsible entity did not demonstrate that it has backup

R#	Lower	Moderate	High	Severe
	functionality (provided either through a facility or contracted services staffed by applicable certified operators) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	functionality (provided either through a facility or contracted services staffed by applicable certified operators) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Medium VRF.	functionality (provided either through a facility or contracted services staffed by applicable certified operators) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a High VRF.	functionality (provided either through a facility or contracted services staffed by applicable certified operators) in accordance with Requirement R4.
R5.	The responsible entity has evidence that its dated, current, in force Operating Plan for backup functionality, was reviewed and approved but it was not done in one calendar year or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes to the capabilities described in Requirement R1.	N/A	The responsible entity has evidence that its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in two calendar years or more or that it was updated more than ninety calendar days after any changes to the capabilities described in Requirement R1.	The responsible entity did not have evidence that its dated, current, in force Operating Plan for backup functionality was reviewed and approved.
R6.	N/A	N/A	N/A	The responsible entity's evidence did not demonstrate that its primary and backup capabilities can independently maintain the functionality required to maintain compliance with Reliability Standards.
R7.	The responsible entity has annually tested its Operating Plan for backup	The responsible entity has annually tested its Operating Plan for	The responsible entity has annually tested its Operating Plan for	The responsible entity did not annually test its Operating Plan for

R#	Lower	Moderate	High	Severe
	functionality, but one of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented.	backup functionality, but two of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented.	backup functionality, but all three of the following occurred: 1) the demonstration was for less than two continuous hours, 2) it failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented.	backup functionality.
R8.	The responsible entity that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months has provided evidence that a plan has been submitted to its Regional Entity showing how it will re-establish backup capability but it was submitted in more than six calendar months.	N/A	N/A	The responsible entity that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months did not submit a plan to its Regional Entity showing how it will re-establish backup.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008
6. Third posting of revised standard on March 17, 2009

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q09. The current draft is the fourth iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit standard for balloting.	August 2009
2. Submit standard for recirculation balloting.	September 2009
3. Submit standard to BOT.	October 2009
4. Submit to regulatory authorities.	November 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.

Effective Date: The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center ~~becomes inoperable~~ functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for a prolonged period of time.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Voice communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement ~~the~~ backup functionality elements identified in Requirement R1 part ~~R~~1.2. The Operating Process shall include at a minimum:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location ~~supporting~~ providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

~~R3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator directing BES operations through other entities shall ensure that backup functionality exists for the BES operations performed through those other entities. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*~~

~~R4.~~R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- ~~R4.1.~~ Planned outages of the primary or backup facilities of two weeks or less
- ~~R4.2.~~ Unplanned outages of the primary or backup facilities

~~R5.~~R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a ~~backup control center~~ facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards ~~-~~that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- ~~R5.1.~~ Planned outages of the primary or backup functionality of two weeks or less
- ~~R5.2.~~ Unplanned outages of the primary or backup functionality

~~R6.~~R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

~~6.1.~~5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1.

~~R7.~~R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that ~~do not depend on each other or any single data center for any~~can independently maintain the functionality required to maintain compliance with Reliability Standards~~ that depend on the primary control functionality~~. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R8.~~R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~8.1.~~7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

~~8.2.~~7.2. The backup functionality for a minimum of two continuous hours.

~~R9.~~R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide a plan to its ~~Reliability Assurer~~ Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location ~~supporting~~providing backup functionality.

~~**M3.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator directing BES operations through other entities shall provide evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities, for backup functionality in accordance with Requirement R3.~~

M~~4~~3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R~~4~~3.

M~~5~~4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a ~~backup control center~~ facility or contracted services staffed by applicable certified operators) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability

Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R~~5~~4.

M~~6~~5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that it~~'~~s dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Requirement R~~6~~5.

M~~7~~6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities ~~do not depend on each other or any common facility for any~~can independently maintain the functionality required to maintain compliance with Reliability Standards ~~that depend on the primary control functionality~~ in accordance with Requirement R~~7~~6.

M~~8~~7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R~~8~~7.

M~~9~~8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide evidence that a plan has been submitted to its ~~Reliability Assurer~~ Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Requirement R~~9~~8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the current year and three previous years in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location ~~supporting~~providing backup functionality, for the current year, in accordance with Measurement M2.

~~Each Reliability Coordinator, Balancing Authority, and Transmission Operator directing BES operations through other entities shall retain its dated, current, in force Operating Plan for backup functionality, providing evidence that it has ensured that backup functionality exists for the BES operations performed through those other entities for the current year and three previous years, in accordance with Measurement M3.~~

- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with ~~r~~Requirement R~~4~~3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M~~4~~3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a ~~backup control center~~ facility or contracted services staffed by applicable certified operators) in accordance with ~~r~~Requirement R~~5~~4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on ~~-~~a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M~~5~~4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the current year and three previous years, that it~~'~~s dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Measurement M~~6~~5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup capabilities ~~do not depend on each other or any common facility for any~~ can independently maintain the functionality required to maintain compliance with Reliability Standards ~~that depend on the primary control functionality~~ in accordance with Measurement M~~7~~6.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M~~8~~7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its ~~Reliability Assurer~~ Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Measurement M~~9~~8.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity ~~has~~had a current Operating Plan for backup functionality but the plan ~~is~~was missing one of the ~~sub-~~requirement's parts (1.1 through 1.6) or the plan does not reflect the date of its last issuance.	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity ~~has~~had a current Operating Plan for backup functionality but the plan ~~is~~was missing two of the ~~sub-~~requirement's parts (1.1 through 1.6).	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity ~~has~~had a current Operating Plan for backup functionality but the plan ~~is~~was missing three or more of the ~~sub-~~requirement's parts (1.1 through 1.6) or is not compliant with Requirement R1, ~~R1~~part 1.5.	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity ~~does~~did not have a current Operating Plan for backup functionality.
R2.	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity ~~has~~had an Operating Plan for backup functionality available at all of its control locations but at one location it ~~is~~was not the current plan.	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity ~~has~~had an Operating Plan for backup functionality available at all of its control locations but at all locations it ~~is~~was not the current plan.	N/A	~~-~~The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity ~~has~~had an Operating Plan for backup functionality but no version of the plan ~~is~~was available at all of its control locations.
~~R3.~~	~~The Reliability Coordinator, Balancing Authority, or Transmission Operator directing BES operations through other entities has not ensured against the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Lower VRF in its Operating Plan for backup functionality.~~	~~The Reliability Coordinator, Balancing Authority, or Transmission Operator directing BES operations through other entities has not ensured against the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a Medium VRF in its Operating Plan for backup functionality.~~	~~The Reliability Coordinator, Balancing Authority, or Transmission Operator directing BES operations through other entities has not ensured against the loss of such entity's control functionality that is depended upon for compliance with one or more Requirements in the Reliability Standards having a High VRF in its Operating Plan for backup functionality.~~	~~The Reliability Coordinator, Balancing Authority, or Transmission Operator directing BES operations through other entities has not ensured against the loss of any such entity's control functionality in its Operating Plan for backup functionality.~~
R~~4~~3.	The Reliability Coordinator has demonstrated that it has a backup	The Reliability Coordinator has demonstrated that it has a backup	The Reliability Coordinator has demonstrated that it has a backup	The Reliability Coordinator ~~has~~did not demonstrate~~d~~ that it has a

R#	Lower	Moderate	High	Severe
	control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R~~4~~3 but it ~~does~~did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R~~4~~3 but it ~~does~~did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R~~4~~3 but it ~~does~~did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	backup control center facility (provided through its own dedicated backup facility or at another entity's control center with certified Reliability Coordinator operators) in accordance with Requirement R~~4~~3.
R~~5~~4.	The ~~Balancing Authority or Transmission Operator~~ responsible entity has demonstrated that it has backup functionality (provided either through a ~~backup control center~~ facility or contracted services staffed by applicable certified operators) in accordance with Requirement R~~5~~4 but it ~~does~~did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to ~~a Balancing Authority and Transmission Operator respectively~~ the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	The ~~Balancing Authority or Transmission Operator~~ responsible entity has demonstrated that it has backup functionality (provided either through a ~~backup control center~~ facility or contracted services staffed by applicable certified operators) in accordance with Requirement R~~5~~4 but it ~~does~~did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to ~~a Balancing Authority and Transmission Operator respectively~~ the responsible entity that depend on the primary control center functionality and which have a	The ~~Balancing Authority or Transmission Operator~~ responsible entity has demonstrated that it has backup functionality (provided either through a ~~backup control center~~ facility or contracted services staffed by applicable certified operators) in accordance with Requirement R~~5~~4 but it ~~does~~did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to ~~a Balancing Authority and Transmission Operator respectively~~ the responsible entity that depend on the primary control center functionality and which have a	The ~~Balancing Authority or Transmission Operator~~ responsible entity ~~has~~did not demonstrate~~d~~ that it has backup functionality (provided either through a ~~backup control center~~ facility or contracted services staffed by applicable certified operators) in accordance with Requirement R~~5~~4.

R#	Lower	Moderate	High	Severe
		Medium VRF.	High VRF.	
R~~6~~5.	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator,~~ responsible entity has evidence that it~~'~~s dated, current, in force Operating Plan for backup functionality, was reviewed and approved but it was not done in one calendar year or that it was updated more than sixty calendar days and less than or equal to ninety calendar days after any changes to the capabilities described in Requirement R1.	N/A	~~-~~The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator,~~ responsible entity has evidence that it~~'~~s dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in two calendar years or more or that it was updated more than ninety calendar days after any changes to the capabilities described in Requirement R1.	~~-~~The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator,~~ responsible entity ~~does~~did not have evidence that it~~'~~s dated, current, in force Operating Plan for backup functionality was reviewed and approved.
R~~7~~6.	N/A	N/A	N/A	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator's~~responsible entity's evidence ~~does~~did not demonstrate that its primary and backup capabilities ~~do not depend on each other or any common facility for the~~ can independently maintain the functionality required to maintain compliance with Reliability Standards ~~that depend on the primary control functionality~~.
R~~8~~7.	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity has annually tested its Operating Plan for backup functionality, but one of the following occurred:	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity has annually tested its Operating Plan for backup functionality, but two of the	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~responsible entity has annually tested its Operating Plan for backup functionality, but all three of the	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity ~~has~~did not annually test~~ed~~ its Operating Plan for backup functionality.

R#	Lower	Moderate	High	Severe
	1) the demonstration was for less than two continuous hours, 2) it ~~has~~ failed to demonstrate that the transition time period is less than or equal to two hours~~.~~, or 3) test results were not documented.	following occurred: 1) the demonstration was for less than two continuous hours, 2) it ~~has~~ failed to demonstrate that the transition time period is less than or equal to two hours, or 3) test results were not documented.	following occurred: 1) the demonstration was for less than two continuous hours, 2) it ~~has~~ failed to demonstrate that the transition time period is less than or equal to two hours, and 3) test results were not documented.	
R~~9~~8.	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months has provided evidence that a plan has been submitted to its ~~Reliability Assurer~~ Regional Entity showing how it will re-establish backup capability but it was submitted in more than six calendar months.	N/A	N/A	The ~~Reliability Coordinator, Balancing Authority, or Transmission Operator~~ responsible entity that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months ~~has~~did not submit~~ted~~ a plan to its ~~Reliability Assurer~~ Regional Entity showing how it will re-establish backup.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Pool and Pre-ballot Window
August 17–September 16, 2009

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2006-04: Backup Facilities

Standard EOP-008-1 — Loss of Control Center Functionality is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on this standard **until 8 a.m. EDT on September 16, 2009**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2006-04_EOP-008-1_BF_in@nerc.com.

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

Project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Applicability of Standards in Project

Reliability Coordinators
Transmission Operators
Balancing Authorities

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open
September 16–28, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2006-04: Backup Facilities

An initial ballot window for proposed standard EOP-008-1 — Loss of Control Center Functionality is now open **until 8 p.m. EDT on September 28, 2009**. An associated implementation plan has been posted with the standard.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

Project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Applicability of Standards in Project

Reliability Coordinators
Transmission Operators
Balancing Authorities

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Ballot Results	
Ballot Name:	Project 2006-04 - Back-up Facilities - EOP-008-1_in
Ballot Period:	9/16/2009 - 9/28/2009
Ballot Type:	Initial
Total # Votes:	215
Total Ballot Pool:	260
Quorum:	**82.69 % The Quorum has been reached**
Weighted Segment Vote:	72.86 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	74	1	41	0.695	18	0.305	1	14
2 - Segment 2.	9	0.6	6	0.6	0	0	1	2
3 - Segment 3.	60	1	33	0.673	16	0.327	3	8
4 - Segment 4.	12	1	5	0.5	5	0.5	0	2
5 - Segment 5.	47	1	22	0.667	11	0.333	3	11
6 - Segment 6.	33	1	17	0.63	10	0.37	2	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	5	0.5	1	0.1	0	2
9 - Segment 9.	9	0.6	6	0.6	0	0	2	1
10 - Segment 10.	8	0.7	6	0.6	1	0.1	0	1
Totals	**260**	**7.5**	**141**	**5.465**	**62**	**2.035**	**12**	**45**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips		
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Negative	View
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Black Hills Corp	Eric Egge		

1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Negative	View
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Negative	View
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	E.ON U.S. LLC	Larry Monday	Negative	View
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Albert Poire	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Kissimmee Utility Authority	Joe B Watson	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	Rodney Hawkins	Affirmative	
1	Long Island Power Authority	Jonathan Appelbaum	Negative	View
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Manuel Couto		
1	Nebraska Public Power District	Richard L. Koch	Affirmative	View
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Lorees Tadros		
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Lawrence R. Larson	Negative	
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Mark Sampson		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Negative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SaskPower	Wayne Guttormson		
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	View
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tampa Electric Co.	Thomas J. Szelistowski		
1	Tennessee Valley Authority	Larry Akens	Negative	View
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo	Negative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View

2	Alberta Electric System Operator	Jason L. Murray	Affirmative	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Greg Tillitson	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Abstain	View
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung		
3	Alabama Power Company	Bobby Kerley	Affirmative	
3	Allegheny Power	Bob Reeping		
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Farmington	Linda R. Jacobson		
3	City of Lansing by its Board of Water and Light	David C Bolan	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow		
3	Cleco Utility Group	Bryan Y Harper		
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Negative	View
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Georgia System Operations Corporation	Edward W. Pourciau	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Negative	View
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Negative	View
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	View
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John Bos	Affirmative	
3	New York Power Authority	Michael Lupo	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	John J. McCawley	Affirmative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young		

3	Southern California Edison Co.	David Schiada	Abstain	
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	Consumers Energy	David Frank Ronk		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	View
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Negative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer		
5	Avista Corp.	Edward F. Groce	Negative	View
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	City of Tallahassee	Alan Gale	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Consolidated Edison Co. of New York	Edwin E Thompson		
5	Consumers Energy	James B Lewis	Negative	View
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Robert Smith	Negative	
5	Dynegy	Greg Mason		
5	Edison Mission Energy	Ellen Oswald		
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner		
5	FPL Energy	Benjamin Church		
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Abstain	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Abstain	
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Louisville Gas and Electric Co.	Charlie Martin	Negative	View
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Northern States Power Co.	Liam Noailles	Negative	View
5	Oglethorpe Power Corporation	Scott McGough	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp Energy	David Godfrey	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Negative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Power LLC	Thomas Piascik	Affirmative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Southeastern Power Administration	Douglas Spencer		
5	Tampa Electric Co.	Frank L Busot	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View

6	Cleco Power LLC	Matthew D Cripps		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Chris Lyons	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Negative	View
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Negative	View
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Louisville Gas and Electric Co.	Daryn Barker	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	PacifiCorp	Gregory D Maxfield	Affirmative	
6	Portland General Electric Co.	John Jamieson	Affirmative	
6	Progress Energy	James Eckelkamp	Negative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Southern California Edison Co.	Marcus V Lotto	Abstain	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8	Dennis Neitzel	Dennis Neitzel	Affirmative	
8	Edward C Stein	Edward C Stein	Affirmative	
8	James A Maenner	James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Negative	View
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
8	Wally Magda	Wally Magda		
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Department of Public Service	Thomas G Dvorsky	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker	Negative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	View
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2006-04: Backup Facilities
The initial ballot for proposed standard EOP-008-1 — Loss of Control Center Functionality ended on September 28, 2009.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 82.69%
Approval: 72.86%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps
As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background
The purpose of the standard is to ensure continued reliable operations of the bulk power system in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

Project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Applicability of Standards in Project
Reliability Coordinators
Transmission Operators
Balancing Authorities

Standards Development Process
The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria
Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Back-up Facilities Standard Drafting Team (Project 2006-04)

Summary Consideration: The comments received were basically re-statements of comments that were issued during the project posting periods and centered on items such as the transition timeframe, independent operation, need for tertiary facilities, etc. Commenters were requesting clarity on these issues prior to adopting the standard. Given the rather large number of clarifying requests, the Standards Committee terminated the voting process and remanded the standard back to the SDT for an additional posting. In response to the Standards Committee's directive and industry comments, the SDT has revised several of the requirements as shown below. Corresponding changes were made to Measures, data retention, and VSLs to bring the wording in those sections up to date with the changes to the requirements.

R1, part 1.1: The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.

R1, part 1.2.1: Tools and applications to ensure that operating personnel have situational awareness of the BES.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during:

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during:

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards.

In addition, the SDT updated the VSLs to comply with the latest guidelines on the drafting of VSLs. As VSLs were not part of the industry request for changes they are not shown in this document but are shown in the revised standard.

The SDT is requesting to post the standard for an additional 30-day comment period.

If you feel that the drafting team overlooked your comments, 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 Vice President and 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 Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Carolyn Ingersoll	Constellation Energy	3	Negative	1. R1 states that the Operating Plan is to address loss of primary control center functionality. However R4 states that Balancing Authorities and Transmission Operators must have backup functionality… "that depend on Balancing Authority and Transmission Operators primary control center functionality respectively." I believe that language is intending to communicate that the back up functionality must be able to perform the same, or similar, functions that are available in the primary control center this is not clear. 2. R4 states that "each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators). The standard should not mandate how an entity ensures that backup functionality exists.
Response: 1. The intent is that the backup functionality must support the reliable operation of the BES and comply with the applicable Reliability Standards. However, the standard addresses only those functions required to support reliability of the BES. Peripheral functionality such as accounting may reside in a primary control center but they are not the concern of this standard. Only those functions that support reliability must be 'backed up'. The quoted phrase is out of context and must be read with the preamble "…sufficient for maintaining compliance with all Reliability Standards…" to provide the proper context. No change made. 2. The standard allows for the flexibility to provide an owned facility or to get the service through contract as stated in FERC Order 693. It provides options so it is not prescriptive and doesn't mandate a particular 'how'. No change made.				
William L. Thompson	Dominion Virginia Power	1	Negative	As written, the clarifications do not appear to have avoided the need for tertiary facilities/functionalities. In fact, the proposed wording implies that there is a need for tertiary facilities/functionalities if a planned outage of more than two weeks is anticipated. An RC or TOP is not likely to assume that some day they might have to plan an outage in excess of two weeks and then go ahead and acquire tertiary facilities/functionalities to have on hand just in case. Therefore, it should be clear that, under normal operations (all systems "Go"), only primary and adequate backup facilities/functionalities are required for compliance. Failure to provide adequate backup in the first place would constitute non-compliance. Under degraded operations (loss of primary facilities/functionalities or loss of the adequate backup facilities/functionalities previously provided), there should be separate and specific requirements for plans an RC or TOP should make and/or actions they should take until normal operations are restored (similar to what R1.6.2 now says but promoted to a stand-alone requirement). Compliance under degraded operations would be evaluated based on these new requirements specific to degraded operations instead of the original requirements to have backup facilities/functionalities. This eliminates the conundrum of being non-compliant when primary or backup facilities/functionalities are lost.

Voter	Entity	Segment	Vote	Comment
Mike Garton	Dominion Resources, Inc.	5	Negative	As written, the clarifications do not appear to have avoided the need for tertiary facilities/functionalities. In fact, the proposed wording implies that there is a need for tertiary facilities/functionalities if a planned outage of more than two weeks is anticipated. An RC or TOP is not likely to assume that some day they might have to plan an outage in excess of two weeks and then go ahead and acquire tertiary facilities/functionalities to have on hand just in case. Therefore, it should be clear that, under normal operations (all systems "Go"), only primary and adequate backup facilities/functionalities are required for compliance. Failure to provide adequate backup in the first place would constitute non-compliance. Under degraded operations (loss of primary facilities/functionalities or loss of the adequate backup facilities/functionalities previously provided), there should be separate and specific requirements for plans an RC or TOP should make and/or actions they should take until normal operations are restored (similar to what R1.6.2 now says but promoted to a stand-alone requirement). Compliance under degraded operations would be evaluated based on these new requirements specific to degraded operations instead of the original requirements to have backup facilities/functionalities. This eliminates the conundrum of being non-compliant when primary or backup facilities/functionalities are lost.
Louis S Slade	Dominion Resources, Inc.	6	Negative	As written, the clarifications do not appear to have avoided the need for tertiary facilities/functionalities. In fact, the proposed wording implies that there is a need for tertiary facilities/functionalities if a planned outage of more than two weeks is anticipated. An RC or TOP is not likely to assume that some day they might have to plan an outage in excess of two weeks and then go ahead and acquire tertiary facilities/functionalities to have on hand just in case. Therefore, it should be clear that, under normal operations (all systems "Go"), only primary and adequate backup facilities/functionalities are required for compliance. Failure to provide adequate backup in the first place would constitute non-compliance. Under degraded operations (loss of primary facilities/functionalities or loss of the adequate backup facilities/functionalities previously provided), there should be separate and specific requirements for plans an RC or TOP should make and/or actions they should take until normal operations are restored (similar to what R1.6.2 now says but promoted to a stand-alone requirement). Compliance under degraded operations would be evaluated based on these new requirements specific to degraded operations instead of the original requirements to have backup facilities/functionalities. This eliminates the conundrum of being non-compliant when primary or backup facilities/functionalities are lost.
Response: The SDT does not intend for entities to have tertiary facilities or functionality. If a planned outage were to take more than the 2 weeks indicated, then the SDT would expect that the affected entity would work with their Region to come up with an acceptable plan to cover the risk involved.				

Voter	Entity	Segment	Vote	Comment
Edward F. Groce	Avista Corp.	5	Negative	We suggest changing the wording in R4 from “Planned outages of the primary or backup facilities of two weeks or less” to “Planned outages of the primary or backup facilities of ten weeks or less". We believe that two weeks is too short a time for the type of remodels that might be required of control center facilities or systems, and the resources and time required to implement a tertiary facility can be substantial compared to the risk. Another approach is to treat planned outages similar to the way unplanned outages are in requirement 8. That is to require a plan to be developed and submitted for longer term planned outages to the Regional Entity.
Scott Kinney	Avista Corp.	1	Negative	We suggest changing the wording in requirement 4 from “Planned outages of the primary or backup facilities of two weeks or less” to “Planned outages of the primary or backup facilities of ten weeks or less". We believe that two weeks is too short a time for the type of remodels that might be required of control center facilities or systems, and the resources and time required to implement a tertiary facility can be substantial compared to the risk. Another approach is to treat planned outages similar to the way unplanned outages are in requirement 8. That is to require a plan to be developed and submitted for longer term planned outages of the primary or backup facility to the Regional Entity.
Donald S. Watkins	Bonneville Power Administration	1	Negative	Regarding R4, BPA suggests changing the wording from “Planned outages of the primary or backup facilities of two weeks or less” to “Planned outages of the primary or backup facilities of four weeks or less.” We believe that 2 weeks may be too short a time for the type of remodels that might be required of control center facilities or systems and suspect there is very little risk with extending the allowed time period to 4 weeks before requiring a tertiary facility.
Rebecca Berdahl	Bonneville Power Administration	3	Negative	Regarding R4, BPA suggests changing the wording from “Planned outages of the primary or backup facilities of two weeks or less” to “Planned outages of the primary or backup facilities of four weeks or less.” We believe that 2 weeks may be too short a time for the type of remodels that might be required of control center facilities or systems and suspect there is very little risk with extending the allowed time period to 4 weeks before requiring a tertiary facility.
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	BPA suggests changing the wording on R4 from: Planned outages of the primary or backup facilities of two weeks or less to Planned outages of the primary or backup facilities of four weeks or less. BPA suggests that a tertiary facility not be required for planned outages of the primary or backup control center facility of up to four weeks. Remodeling of a facility may take longer than two weeks. That would result in requiring the expense of finding a tertiary facility that's not needed for a 3 to 4 week construction period.

Voter	Entity	Segment	Vote	Comment
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	regarding R4: BPA suggests changing the wording from: Planned outages of the primary or backup facilities of two weeks or less to: Planned outages of the primary or backup facilities of four weeks or less BPA also suggests that a tertiary facility not be required for planned outages of the primary or backup control center facility of up to four weeks. Remodeling of a facility may take longer than two weeks. That would result in requiring the expense of finding a tertiary facility that's not needed for a 3 to 4 week construction period.
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Negative	The District suggest changing the wording in R4 from "Planned outages of the primary or backup facilities of two weeks or less" to "Planned outages of the primary or backup facilities of four weeks or less." Two weeks may be too short a time for the type of remodels that might be required of control center facilities or systems. Extending the allowed time period to four weeks before requiring a tertiary facility would be a reasonable requirement.
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Negative	The only change would be to alter the wording in R4 from "Planned outages of the primary or backup facilities of two weeks or less" to "Planned outages of the primary or backup facilities of four weeks or less." We believe that two weeks may be too short a time for the type of remodels that might be required of control center facilities or systems and suspect there is very little risk with extending the allowed time period to four weeks before requiring a tertiary facility.
Richard Salgo	Sierra Pacific Power Co.	1	Affirmative	Affirmative vote, but would still suggest a minor language change in R4 to increase the duration of planned outages of backup or primary control centers from 2 weeks to 30 days (or 4 weeks). This would better accommodate construction and re-model projects in the control center without posing any significant risk.
Response: The SDT intended that a backup facility/functionality is required to support the loss of the primary facility. The SDT debated the length of time to use for this requirement and has vetted it through the industry comment periods to date. The majority of respondents are comfortable with the two week figure. No change made.				

Voter	Entity	Segment	Vote	Comment
Jeff Knottek	City Utilities of Springfield, Missouri	1	Negative	City Utilities of Springfield, Missouri casts a negative vote with the following request for the drafting team. Remove R1.2. from the standard. Since R1.3. requires "An Operating Process for keeping the backup functionality consistent with the primary control center" and all items listed in R1.2. except R1.2.4. are already required for the primary control center in other NERC Standards, to list them again is redundant and unnecessary. 1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES. (TOP-006 R2., R5., R7 and IRO-002 R5. - R8.) 1.2.2. Data communications. (TOP-005 and IRO-002 R1. - R3.) 1.2.3. Voice communications. (COM-001 R1. and IRO-002 R1.) 1.2.4. Power source(s). (Power source(s)" is an obvious need to maintain functionality consistent with the primary control center and doesn't need to be a requirement in the standard.) 1.2.5. Physical and cyber security. (CIP-002 through CIP-009)
Bruce Merrill	Lincoln Electric System	3	Negative	LES is concerned with the inclusion of "Physical and cyber Security" in R1.2.5. This requirement could be incorrectly interpreted to mean that all backup facilities are Critical Assets and must meet the CIP-003 to CIP-009 requirements. In CIP-002 a company is required to create a risk based methodology and determine which of their assets are Critical Assets. CIP-002-1 R1.2.1 requires that the risk based methodology include backup control centers. LES believes that EOP-008-1 R1.2.5 is at best confusing and at worst duplicative, and should therefore be removed. Additionally, the Requirements 1.2.1 - 1.2.5 are a ' list of elements required to support the backup functionality' per R1.2. The first 4 elements (tools, data communication, voice communication, and power sources) are indeed needed to support backup functionality, however the 5th element "Physical and cyber security" is not needed to support backup functionality. This serves to further our case that R1.2.5 should be removed from this standard.
Dennis Florom	Lincoln Electric System	5	Negative	LES is concerned with the inclusion of "Physical and cyber Security" in R1.2.5. This requirement could be incorrectly interpreted to mean that all backup facilities are Critical Assets and must meet the CIP-003 to CIP-009 requirements. In CIP-002 a company is required to create a risk based methodology and determine which of their assets are Critical Assets. CIP-002-1 R1.2.1 requires that the risk based methodology include backup control centers. LES believes that EOP-008-1 R1.2.5 is at best confusing and at worst duplicative, and should therefore be removed. Additionally, the Requirements 1.2.1 - 1.2.5 are a 'list of elements required to support the backup functionality' per R1.2. The first 4 elements (tools, data communication, voice communication, and power sources) are indeed needed to support backup functionality, however the 5th element "Physical and cyber security" is not needed to support backup functionality. This serves to further our case that R1.2.5 should be removed from this standard.

Voter	Entity	Segment	Vote	Comment
Eric Ruskamp	Lincoln Electric System	6	Negative	LES is concerned with the inclusion of "Physical and cyber Security" in R1.2.5. This requirement could be incorrectly interpreted to mean that all backup facilities are Critical Assets and must meet the CIP-003 to CIP-009 requirements. In CIP-002 a company is required to create a risk based methodology and determine which of their assets are Critical Assets. CIP-002-1 R1.2.1 requires that the risk based methodology include backup control centers. LES believes that EOP-008-1 R1.2.5 is at best confusing and at worst duplicative, and should therefore be removed. Additionally, the Requirements 1.2.1 - 1.2.5 are a ' list of elements required to support the backup functionality' per R1.2. The first 4 elements (tools, data communication, voice communication, and power sources) are indeed needed to support backup functionality, however the 5th element "Physical and cyber security" is not needed to support backup functionality. This serves to further our case that R1.2.5 should be removed from this standard.
Response: The items listed in Requirement R1, part 1.2 are simply a list of items that must be addressed in the plan and are not performance requirements so no duplication occurs. The other standards cited would still dictate the performance requirements for those elements. No change made.				
Douglas E. Hils	Duke Energy Carolina	1	Negative	Duke Energy appreciates the work of the drafting team on this subject; regretfully we must vote against this ballot knowing that another SAR must be submitted if the ballot fails. It is our opinion that Requirements R3 and R4 should be modified to clarify that a backup facility does not have to be continuously staffed by applicable certified operators, and that applicable functional entities are allowed a two-hour transition period to fully implement the backup functionality, as specified in R1.5. Requirement R6 should be clarified to indicate the degree of independence that must be maintained between the primary and backup capabilities. Thank you.
Response: It is the intent of Requirements R3 & R4 that when the backup facility is activated it then be staffed by certified operators. The SDT has clarified this intent in revised Requirements R3 & R4 (with corresponding changes to Measures, data retention, and the VSLs). The SDT confirms that entities are provided a two-hour transition period to fully implement the backup functionality. **R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: **R4**. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: R6: The intent of the requirement is that you can't depend on your primary facility for adequate functionality at your backup facility/functionality (or vice versa) for compliance to the Reliability Standards. This means that nothing at your backup facility/functionality can depend on anything at your primary facility for any				

Voter	Entity	Segment	Vote	Comment
item that would be required for you to maintain compliance with all applicable Reliability Standards at your backup facility/functionality (or vice versa). The requirement is not intended to encompass equipment typically located outside of the control center such as RTUs. Requirement R6 has been revised to provide additional clarity on this point (with corresponding changes to Measure M6, data retention, and the VSLs). **R6**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards.				
Larry Monday	E.ON U.S. LLC	1	Negative	E.ON U.S. requests that the SDT clarify what is meant in Requirement 1.2.1 by: "Tools and applications that allow visualization capabilities to ensure that operating personnel have situational awareness of the BES" Does this require the same functionality at the backup control center that is available at the primary control center, for example, a video wall? E.ON U.S. requests that the SDT specify if requirement 6 requires data communications be independent for 100% of the RTUs brought back via SCADA or just those RTUs located at "Critical Facilities." E.ON U.S. believes that R4 and M4 should be reworded to clarify that a backup control facility does not require staffing 24x7 by certified operators unless performing as the primary control center.
Charles A. Freibert	Louisville Gas and Electric Co.	3	Negative	E.ON U.S. requests that the SDT clarify what is meant in Requirement 1.2.1 by: "Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES" Does this require the same functionality at the backup control center that is available at the primary control center, for example, a video wall? E.ON U.S. requests that the SDT specify if requirement 6 requires data communications be independent for 100% of the RTUs brought back via SCADA or just those RTUs located at "Critical Facilities." E.ON U.S. believes that R4 and M4 should be reworded to clarify that a backup control facility does not require staffing 24x7 unless contracting for backup services.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	E.ON U.S. requests that the SDT clarify what is meant in Requirement 1.2.1 by: "Tools and applications that allow visualization capabilities the ensure that operating personnel have situational awareness of the BES" Does this require the same functionality at the backup control center that is available at the primary control center, for example, a video wall? E.ON U.S. requests that the SDT specify if requirement 6 requires data communications be independent for 100% of the RTUs brought back via SCADA or just those RTUs located at "Critical Facilities." E.ON U.S. believes that R4 and M4 should be reworded to clarify that a backup control facility

Voter	Entity	Segment	Vote	Comment
				does not require staffing 24x7 unless contracting for backup services.
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	E.ON U.S. requests that the SDT clarify what is meant in Requirement 1.2.1 by: “Tools and applications that allow visualization capabilities the ensure that operating personnel have situational awareness of the BES” Does this require the same functionality at the backup control center that is available at the primary control center, for example, a video wall? E.ON U.S. requests that the SDT specify if requirement 6 requires data communications be independent for 100% of the RTUs brought back via SCADA or just those RTUs located at “Critical Facilities.” E.ON U.S. believes that R4 and M4 should be reworded to clarify that a backup control facility does not require staffing 24x7 unless contracting for backup services.

Response: R 1.2.1: The SDT intends that there is sufficient backup functionality so that the operators should have within their back-up capabilities enough functionality that the operators have situational awareness, but this does not mean it must be in the same format as the primary facility, to enable reliable operation of the BES and satisfy all standards applicable to the Registered Entity. Requirement R1, part 1.2.1 has been revised to provide clarity in this regard.

> **R1, part 1.2.1**: Tools and applications to ensure that operating personnel have situational awareness of the BES.

R6: The intent of the requirement is that you can’t depend on your primary facility for adequate functionality at your backup facility/functionality (or vice versa) for compliance to the Reliability Standards. This means that nothing at your backup facility/functionality can depend on anything at your primary facility for any item that would be required for you to maintain compliance with all applicable Reliability Standards at your backup facility/functionality (or vice versa). The requirement is not intended to encompass equipment typically located outside of the control center such as RTUs. Requirement R6 has been revised to provide additional clarity on this point (with corresponding changes to Measure M6, data retention, and the VSLs).

> **R6**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards.

R4: It is the intent of Requirement R4 that when the backup facility is activated it then be staffed by certified operators. The SDT has clarified this intent in a revised Requirement R4 (with corresponding changes to Measure M4, data retention, and the VSLs).

> **R4**. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator’s primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during:

Voter	Entity	Segment	Vote	Comment
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work put forth in this standards development effort. We feel that the standard proposed is a significant improvement over the existing Version 0 standard. However, as per our following explanation, we must vote Negative due to the ambiguity that still remains in one of the requirements. Requirement R6 states: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards." This requirement is ambiguous and subject to varying interpretations regarding the phrase “can independently maintain” which could include the need for redundancy of RTU's and their associated communications equipment. We understand that the team tried to alleviate this specific concern with the latest revision to R6, but the requirement can still be misinterpreted. We suggest a change to the requirement as follows: "R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and back-up capabilities that do not depend on each other to maintain operational functionality in accordance with the applicable NERC Reliability Standards."
Joanne Kathleen Borrell	FirstEnergy Solutions	3	Negative	FirstEnergy appreciates the hard work put forth in this standards development effort. We feel that the standard proposed is a significant improvement over the existing Version 0 standard. However, as per our following explanation, we must vote Negative due to the ambiguity that still remains in one of the requirements. Requirement R6 states: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards." This requirement is ambiguous and subject to varying interpretations regarding the phrase “can independently maintain” which could include the need for redundancy of RTU's and their associated communications equipment. We understand that the team tried to alleviate this specific concern with the latest revision to R6, but the requirement can still be misinterpreted. We suggest a change to the requirement as follows: "R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and back-up capabilities that do not depend on each other to maintain operational functionality in accordance with the applicable NERC Reliability Standards."

Voter	Entity	Segment	Vote	Comment
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	FirstEnergy appreciates the hard work put forth in this standards development effort. We feel that the standard proposed is a significant improvement over the existing Version 0 standard. However, as per our following explanation, we must vote Negative due to the ambiguity that still remains in one of the requirements. Requirement R6 states: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards." This requirement is ambiguous and subject to varying interpretations regarding the phrase "can independently maintain" which could include the need for redundancy of RTU's and their associated communications equipment. We understand that the team tried to alleviate this specific concern with the latest revision to R6, but the requirement can still be misinterpreted. We suggest a change to the requirement as follows: "R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and back-up capabilities that do not depend on each other to maintain operational functionality in accordance with the applicable NERC Reliability Standards."
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	FirstEnergy appreciates the hard work put forth in this standards development effort. We feel that the standard proposed is a significant improvement over the existing Version 0 standard. However, as per our following explanation, we must vote Negative due to the ambiguity that still remains in one of the requirements. Requirement R6 states: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that can independently maintain the functionality required to maintain compliance with Reliability Standards." This requirement is ambiguous and subject to varying interpretations regarding the phrase “can independently maintain” which could include the need for redundancy of RTU's and their associated communications equipment. We understand that the team tried to alleviate this specific concern with the latest revision to R6, but the requirement can still be misinterpreted. We suggest a change to the requirement as follows: "R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and back-up capabilities that do not depend on each other to maintain operational functionality in accordance with the applicable NERC Reliability Standards."

Response: R6: The intent of the requirement is that you can’t depend on your primary facility for adequate functionality at your backup facility/functionality (or vice versa) for compliance to the Reliability Standards. This means that nothing at your backup facility/functionality can depend on anything at your primary facility for any item that would be required for you to maintain compliance with all applicable Reliability Standards at your backup facility/functionality (or vice versa). The requirement is not intended to encompass equipment typically located outside of the control center such as RTUs. Requirement R6 has been revised to provide additional clarity on this point (with corresponding changes to Measure M6, data retention, and the VSLs).

> **R6**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards.

Voter	Entity	Segment	Vote	Comment
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	In R1.1, we feel the use of the phrase “prolonged period of time” is unnecessary and misleading. Backup functionality should be required for as long as the primary control center is not available. There should be no indication of a time frame established in the standard, whether prolonged or short. We recommend removal of “for a prolonged period of time” from R1.1 in order for this to be clear and concise.
Michael Ibold	Xcel Energy, Inc.	3	Negative	In R1.1, we feel the use of the phrase “prolonged period of time” is unnecessary and misleading. Backup functionality should be required for as long as the primary control center is not available. There should be no indication of a time frame established in the standard, whether prolonged or short. We recommend removal of “for a prolonged period of time” from R1.1 in order for this to be clear and concise.
Liam Noailles	Northern States Power Co.	5	Negative	In R1.1, we feel the use of the phrase “prolonged period of time” is unnecessary and misleading. Backup functionality should be required for as long as the primary control center is not available. There should be no indication of a time frame established in the standard, whether prolonged or short. We recommend removal of “for a prolonged period of time” from R1.1 in order for this to be clear and concise.
David F. Lemmons	Xcel Energy, Inc.	6	Negative	In R1.1, we feel the use of the phrase “prolonged period of time” is unnecessary and misleading. Backup functionality should be required for as long as the primary control center is not available. There should be no indication of a time frame established in the standard, whether prolonged or short. We recommend removal of “for a prolonged period of time” from R1.1 in order for this to be clear and concise.
Response: R1.1: The SDT was following the language in FERC’s directive. The FERC directive per Order 693 required that the backup “*be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center*”. However, the SDT agrees that additional clarity could be provided and has revised Requirement R1, part 1.1 accordingly. **R1, part 1.1:** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.				
Garry Baker	JEA	3	Negative	JEA feels that R1.4 should be an operating process as opposed to an operating procedure based on the definition in the NERC Glossary.
Response: The intent is that the specific steps to be taken to implement the Operating Plan be described. This is a procedure as opposed to a process as defined in the NERC Glossary. No change made.				

Voter	Entity	Segment	Vote	Comment
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Negative	MGE disagrees with this balloted standard due to the following issues, a) R1.2.5 is redundant with CIP-002-1, R1.2.1 where Critical asset indentification contains backup control centers, b) R1.5 requires a two hour time frame for an entity to fully implement the backup functionality, this may not be enough time for entities that may be impacted by hurricanes, floods, ect, c) R6 has an addition of "can independently maintain the functionally required to maintain compliance with reliability standards" this may be interpretated as requiring dual rtu's, breakers, lines, scada systems, ect.
Response: The items listed in Requirement R1, part 1.2 are simply a list of items that must be addressed in the entity's Operating Plan in the event that an entity's primary control center functionality is lost. CIP-002-1, Requirement R1.2.1 requires the entity to consider its control centers when developing a methodology for identification of critical assets so no duplication occurs. No change made. R1.5: The SDT has vetted the two-hour time frame through multiple industry comment periods and the vast majority of the industry has indicated acceptance of this value. No change made. R6: The intent of the requirement is that you can't depend on your primary facility for adequate functionality at your backup facility/functionality (or vice versa) for compliance to the Reliability Standards. This means that nothing at your backup facility/functionality can depend on anything at your primary facility for any item that would be required for you to maintain compliance with all applicable Reliability Standards at your backup facility/functionality (or vice versa). The requirement is not intended to encompass equipment typically located outside of the control center such as RTUs. Requirement R6 has been revised to provide additional clarity on this point (with corresponding changes to Measure M6, data retention, and the VSLs). **R6**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards.				
Terry L Baker	Platte River Power Authority	3	Negative	PRPA does not feel that the Operating Plan should include a summary description of the Physical and Cyber security elements required to support backup functionality. This should already be covered in meeting the CIP standards and is an unnecessary duplication. (R1.2.5) PRPA feels that we understand the intent of R.4 but the requirement is written in a manner that could lead you to believe the backup center would be dependent on primary control center functionality for "maintaining compliance with all Reliability Standards". PRPA does not see the reliability value in being required to approve our Operating Plan after completing the annual review. (R.5)
Response: The items listed in Requirement R1, part 1.2 are simply a list of items that must be addressed in the entity's Operating Plan in the event that an entity's primary control center functionality is lost. CIP-002-1, Requirement R1.2.1 requires the entity to consider its control centers when developing a methodology for identification of critical assets so no duplication occurs. No change made. R4: The intent is that the backup functionality must support the reliable operation of the BES and comply with the applicable Reliability Standards. However, the standard addresses only those functions required to support reliability of the BES. Peripheral functionality such as accounting may reside in a primary control				

Voter	Entity	Segment	Vote	Comment
center but they are not the concern of this standard. Only those functions that support reliability must be 'backed up'. The quoted phrase is out of context and should include the words following that phrase to provide the proper context: "...maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality..." This now provides the proper context for describing the intent of the SDT. No change made. R5: The intent is to ensure that management responsible for compliance as identified in the corporate compliance program is aware of changes to the Operating Plan and approves them. No change made.				
Jonathan Appelbaum	Long Island Power Authority	1	Negative	R1.4 should be modified such that the Operating Plan provides 1. The NERC Certified Operator the authority to implement the Operating Plan; and 2. An Operating Process is provided describing the parameters to consider for the implementation of the Operating Plan. Concern is an Auditor will want to see a Procedure as NERC defines an Operating Procedure. That is a specific step by step process that the NERC Certified Operator takes to decide when to implement the Operating Plan. An Operating Process is more appropriate terminology. Also note that R1.3 and 1.6 uses an Operating Process not a Procedure.
Response: The authority to implement the Operating Plan is up to the Registered Entity to identify in the procedure. The intent is that the specific steps to be taken to implement the Operating Plan be described. This is a procedure as opposed to a process as defined in the NERC Glossary. No change made.				
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Negative	Requirement 1.1 - We believe the statement should say for as long as required, not for a prolonged period of time. Requirement 1.5 - We believe 2 hours to get the backup system totally functioning is unreasonable, especially if the backup is located a significant distance from the primary. We believe the standard should allow an alternative plan (manual dispatch), and have the backup operating within a reasonable time after the alternative plan is operating. Requirement 6 - We are concerned that the phrase "independently maintain" could be interpreted to require complete redundancy from the sensing device all the way to the backup center. This needs to be clarified.
Response: R1.1: The SDT was following the language in FERC's directive. The FERC directive per Order 693 required that the backup "*be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center*". However, the SDT agrees that additional clarity could be provided and has revised Requirement R1, part 1.1 accordingly. **R1, part 1.1:** The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality. R1.5: The SDT has vetted the two-hour time frame through multiple industry comment periods and the vast majority of the industry has indicated acceptance of this value. No change made. R6: The intent of the requirement is that you can't depend on your primary facility for adequate functionality at your backup facility/functionality (or vice versa) for				

Voter	Entity	Segment	Vote	Comment
compliance to the Reliability Standards. This means that nothing at your backup facility/functionality can depend on anything at your primary facility for any item that would be required for you to maintain compliance with all applicable Reliability Standards at your backup facility/functionality (or vice versa). The requirement is not intended to encompass equipment typically located outside of the control center such as RTUs. Requirement R6 has been revised to provide additional clarity on this point (with corresponding changes to Measure M6, data retention, and the VSLs). **R6**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards.				
James R. Keller	Wisconsin Electric Power Marketing	3	Negative	Specific Comments: R1. 1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES. Comment: R1.2.1 should be removed. "Situational Awareness" is a state of knowledge, not a measurable state of a control room facility. Personal background and other factors dictate the minimum information an operator needs to understand the state of the BES, making this a subjective requirement. We cannot ensure the state of mind of operators; only provide tools to assist in the development of awareness. 1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality. Comment: The latter part of R1.6.2 is a departure from the main R1.6, and planned and unplanned outages are addressed in R3 for RCs, and R4 for BAs and TOPs. Should be modified as shown above. R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming. To avoid requiring tertiary functionality, backup functionality is not required during: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] Comment: The statement "sufficient for maintaining compliance with all Reliability Standards" is subjective and should be remove as shown above. R5. 5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1. Comment: R5.1 is an unnecessary administrative burden and is further highly subjective in the interpretation of what constitutes "any change in capability." These types of revisions are addressed by the annual review in requirement 5. R5.1 should be removed. R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have backup capabilities that are independent from the primary control center. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] Comment: The project title is "Back-up Facilities Project 2006-04," the SAR does not mention primary control centers, and the standard is titled "Loss of Control Center Functionality." Therefore, requirements placed on primary control centers are over reaching, and do not belong here.

Voter	Entity	Segment	Vote	Comment
				Comment: "Functionality required to maintain compliance with Reliability Standards" is redundant with other standard requirements. This is a minor variation on requiring compliance to Reliability Standards. R6 should be modified as shown above. M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) includes monitoring, control, logging, and alarming. Comment: The statement "sufficient for maintaining compliance with all Reliability Standards" is subjective and should be removed as shown above. M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its backup capabilities are independent from the primary control center in accordance with Requirement R6. Comment: The project title is "Back-up Facilities Project 2006-04," the SAR does not mention primary control centers, and the standard is titled "Loss of Control Center Functionality." Therefore, requirements placed on primary control centers are over reaching, and do not belong here. M6 should be modified as shown above.
Anthony Jankowski	Wisconsin Energy Corp.	4	Negative	Specific Comments: R1. 1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES. Comment: R1.2.1 should be removed. "Situational Awareness" is a state of knowledge, not a measurable state of a control room facility. Personal background and other factors dictate the minimum information an operator needs to understand the state of the BES, making this a subjective requirement. We cannot ensure the state of mind of operators; only provide tools to assist in the development of awareness. 1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality. Comment: The latter part of R1.6.2 is a departure from the main R1.6, and planned and unplanned outages are addressed in R3 for RCs, and R4 for BAs and TOPs. Should be modified as shown above. R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) that includes monitoring, control, logging, and alarming. To avoid requiring tertiary functionality, backup functionality is not required during: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] Comment: The statement "sufficient for maintaining compliance with all Reliability Standards" is subjective and should be remove as shown above. R5. 5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1. Comment: R5.1 is an unnecessary administrative burden and is further highly subjective in the

Voter	Entity	Segment	Vote	Comment
				interpretation of what constitutes "any change in capability." These types of revisions are addressed by the annual review in requirement 5. R5.1 should be removed. R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have backup capabilities that are independent from the primary control center. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] Comment: The project title is "Back-up Facilities Project 2006-04," the SAR does not mention primary control centers, and the standard is titled "Loss of Control Center Functionality." Therefore, requirements placed on primary control centers are over reaching, and do not belong here. Comment: "Functionality required to maintain compliance with Reliability Standards" is redundant with other standard requirements. This is a minor variation on requiring compliance to Reliability Standards. R6 should be modified as shown above. M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) includes monitoring, control, logging, and alarming. Comment: The statement "sufficient for maintaining compliance with all Reliability Standards" is subjective and should be removed as shown above. M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its backup capabilities are independent from the primary control center in accordance with Requirement R6. Comment: The project title is "Back-up Facilities Project 2006-04," the SAR does not mention primary control centers, and the standard is titled "Loss of Control Center Functionality." Therefore, requirements placed on primary control centers are over reaching, and do not belong here. M6 should be modified as shown above.
Linda Horn	Wisconsin Electric Power Co.	5	Negative	Specific Comments: R1. 1.2.1. Tools and applications that allow visualization capabilities that ensure that operating personnel have situational awareness of the BES. Comment: R1.2.1 should be removed. "Situational Awareness" is a state of knowledge, not a measurable state of a control room facility. Personal background and other factors dictate the minimum information an operator needs to understand the state of the BES, making this a subjective requirement. We cannot ensure the state of mind of operators; only provide tools to assist in the development of awareness. 1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality. Comment: The latter part of R1.6.2 is a departure from the main R1.6, and planned and unplanned outages are addressed in R3 for RCs, and R4 for BAs and TOPs. Should be modified as shown above. R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified

Voter	Entity	Segment	Vote	Comment
				operators) that includes monitoring, control, logging, and alarming. To avoid requiring tertiary functionality, backup functionality is not required during: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] Comment: The statement "sufficient for maintaining compliance with all Reliability Standards" is subjective and should be remove as shown above. R5. 5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1. Comment: R5.1 is an unnecessary administrative burden and is further highly subjective in the interpretation of what constitutes "any change in capability." These types of revisions are addressed by the annual review in requirement 5. R5.1 should be removed. R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have backup capabilities that are independent from the primary control center. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] Comment: The project title is "Back-up Facilities Project 2006-04," the SAR does not mention primary control centers, and the standard is titled "Loss of Control Center Functionality." Therefore, requirements placed on primary control centers are over reaching, and do not belong here. Comment: "Functionality required to maintain compliance with Reliability Standards" is redundant with other standard requirements. This is a minor variation on requiring compliance to Reliability Standards. R6 should be modified as shown above. M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators) includes monitoring, control, logging, and alarming. Comment: The statement "sufficient for maintaining compliance with all Reliability Standards" is subjective and should be removed as shown above. M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its backup capabilities are independent from the primary control center in accordance with Requirement R6. Comment: The project title is "Back-up Facilities Project 2006-04," the SAR does not mention primary control centers, and the standard is titled "Loss of Control Center Functionality." Therefore, requirements placed on primary control centers are over reaching, and do not belong here. M6 should be modified as shown above.

Response: R 1.2.1: The SDT intends that there is sufficient backup functionality so that the operators should have within their back-up capabilities enough functionality that the operators have situational awareness, but this does not mean it must be in the same format as the primary facility, to enable reliable operation of the BES and satisfy all standards applicable to the Registered Entity. Requirement R1, part 1.2.1 has been revised to provide clarity in this regard.

R1, part 1.2.1: Tools and applications to ensure that operating personnel have situational awareness of the BES.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">R1.6.2: This requirement is to ensure that there is a plan to mitigate the risk during transition and outages. Since no such plan is mentioned in Requirements R3 & R4 there is no redundancy or contradiction. No change made.

R4: The intent is that the backup functionality must support the reliable operation of the BES and comply with the applicable Reliability Standards. However, the standard addresses only those functions required to support reliability of the BES. Peripheral functionality such as accounting may reside in a primary control center but they are not the concern of this standard. Only those functions that support reliability must be ‘backed up’. No change made.

R 5.1: The SDT feels that waiting one year to track changes to the Operating Plan is unrealistic for such an important plan. Sixty days should be sufficient time to incorporate changes to the plan. The use of the term ‘any’ can sometimes be considered as too broad for inclusion in a standard. However, in this case, ‘any’ is bound by the parts of Requirement R1 which lay out what specific information is required in the Operating Plan. Therefore, in this context, ‘any’ is not too broad and is the appropriate term to use. No change made.

R6: There are no requirements for the primary facility in this standard. The intent of the requirement is that you can’t depend on your primary facility for adequate functionality at your backup facility/functionality (or vice versa) for compliance to the Reliability Standards. This means that nothing at your backup facility/functionality can depend on anything at your primary facility for any item that would be required for you to maintain compliance with all applicable Reliability Standards at your backup facility/functionality (or vice versa). The requirement is not intended to encompass equipment typically located outside of the control center such as RTUs. Requirement R6 has been revised to provide additional clarity on this point (with corresponding changes to Measure M6, data retention, and the VSLs).

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards.

M4: See response to R4 above.

M6: See response to R6 above.</td></tr>
<tr><td>Jalal (John) Babik</td><td>Dominion Resources, Inc.</td><td>3</td><td>Negative</td><td>The reason is that the revised language that was supposed to eliminate the need for a tertiary backup facility is so poorly worded that it actually creates an unintentional requirement for a tertiary facility if a planned outage of the primary or secondary facility exceeds two weeks. We commented on this, and the SDT response was that, as “standard operating procedure”, an outage of greater than two weeks is supposed to be reported to the Region along with a mitigation plan. We cannot find this reporting requirement in the proposed standard or any other standard.</td></tr>
<tr><td colspan="5">Response: The NERC compliance process requires that if a standard requirement cannot be met the Registered Entity must report this to the Regional Entity and explain why it cannot be met along with a plan for mitigating the non-compliance. No change made.</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Lee Schuster	Florida Power Corporation	3	Negative	The Standard Drafting Team has clarified many requirements in its responses to industry questions/comments. However, some of these clarifications were not added to the standard. Examples include “prolonged period of time” and “annual test.” This has resulted in repeated questions/comments across draft revisions because the clarifications were only in the SDT’s responses from previous revisions. These clarifications should either be (1) added to the standard or (2) included in a FAQ document for the standard. Otherwise, these same questions will persist during audits, which will potentially lead to inconsistent adherence to the standard and inconsistent interpretation during audits.
Sam Waters	Progress Energy Carolinas	3	Negative	The Standard Drafting Team has clarified many requirements in its responses to industry questions/comments. However, some of these clarifications were not added to the standard. Examples include “prolonged period of time” and “annual test.” This has resulted in repeated questions/comments across draft revisions because the clarifications were only in the SDT’s responses from previous revisions. These clarifications should either be (1) added to the standard or (2) included in a FAQ document for the standard. Otherwise, these same questions will persist during audits, which will potentially lead to inconsistent adherence to the standard and inconsistent interpretation during audits.
Wayne Lewis	Progress Energy Carolinas	5	Negative	The Standard Drafting Team has clarified many requirements in its responses to industry questions/comments. However, some of these clarifications were not added to the standard. Examples include “prolonged period of time” and “annual test.” This has resulted in repeated questions/comments across draft revisions because the clarifications were only in the SDT’s responses from previous revisions. These clarifications should either be (1) added to the standard or (2) included in a FAQ document for the standard. Otherwise, these same questions will persist during audits, which will potentially lead to inconsistent adherence to the standard and inconsistent interpretation during audits.
Response: The SDT believes it has attempted to clarify issues raised during all comment periods. However, in response to industry comments requesting additional clarity, the SDT has revised Requirement R1, part 1.1 (“prolonged period of time”). **R1, part 1.2.1**: Tools and applications to ensure that operating personnel have situational awareness of the BES. However, with regard to ‘annual’: standards procedure is not to ‘define’ terms that are commonly used or where the term is readily available in a dictionary. Annual is defined in Webster’s as “occurring or happening every year or once a year”. The SDT confirms that this is the meaning intended. No change made.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	The standards needs clarification to allow for natural disasters where it may take more than 2 hours to transport personnel to the backup control center such as a flood. Natural disasters can easily jam roads.

Voter	Entity	Segment	Vote	Comment
Response: A standard cannot handle any and all possible scenarios but should instead address what is reasonable and what the requirement should be for reliable operation of the bulk power system. In cases such as described here, Registered Entities would need to notify the Regional Entity of the situation as it occurs. The SDT has vetted the two-hour time frame through multiple industry comment periods and the vast majority of the industry has indicated acceptance of this value. No change made.				
Peggy Abbadini	Power Energy Group LLC	8	Negative	There is still interpretation issues on what will be expected for compliance concerning CIP Standards when the language in R4 states “maintaining compliance with all Reliability Standards”.
Response: The CIP standards apply to the backup as well as the primary facility. There should be no confusion here. No change made.				
Larry Akens	Tennessee Valley Authority	1	Negative	TVA believes that the word “any” in Requirement 5.1 is too broad.
Response: The use of the term ‘any’ can sometimes be considered as too broad for inclusion in a standard. However, in this case, ‘any’ is bound by the parts of Requirement R1 which lay out what specific information is required in the Operating Plan. Therefore, in this context, ‘any’ is not too broad and is the appropriate term to use. No change made.				
Dan R Schoenecker	Midwest Reliability Organization	10	Negative	Various concerns exist among the MRO NSRS membership.
Response: The comment is not specific regarding the MRO NSRS concerns. No change made.				
Martin Bauer	U.S. Bureau of Reclamation	5	Negative	We are inclined to vote against with the standard following comment "Documentation concerning changes to the standards must be communicated through an open and transparent process. It is troubling to find that the reason for a change will not be produced during the standard review process but is intended to be submitted after the fact. This practice should be avoided. This is in reference to the statement "The Standards Committee (SC) instructed the SDT to remove R3 after the SC was told by NERC Staff that the requirements in R3 are addressed through compliance administration processes and the industry is already being audited in accordance with these processes..."
Response: The majority of the comments received to this issue in posting three were to remove the requirement. A minority of commenters pointed out a possible reliability gap that caused the SDT to retain the requirement despite the majority comments. Subsequently, the Standards Committee instructed the SDT to remove the requirement. If there is a problem with the process that was followed, comments should be addressed to the Standards Committee.				

Voter	Entity	Segment	Vote	Comment
David A. Lapinski	Consumers Energy	3	Negative	We believe that the old R3 should be removed. R6 lacks a definitive statement as to what "independently maintain" means. Clarification is needed.
James B Lewis	Consumers Energy	5	Negative	We believe that the old R3 should be removed. R6 lacks a definitive statement as to what "independently maintain" means. Clarification is needed.
Response: R3: The requirement was removed. R6: There are no requirements for the primary facility in this standard. The intent of the requirement is that you can't depend on your primary facility for adequate functionality at your backup facility/functionality (or vice versa) for compliance to the Reliability Standards. This means that nothing at your backup facility/functionality can depend on anything at your primary facility for any item that would be required for you to maintain compliance with all applicable Reliability Standards at your backup facility/functionality (or vice versa). The requirement is not intended to encompass equipment typically located outside of the control center such as RTUs. Requirement R6 has been revised to provide additional clarity on this point (with corresponding changes to Measure M6, data retention, and the VSLs). **R6**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards.				
Richard L. Koch	Nebraska Public Power District	1	Affirmative	The implementation schedule should be extended from 24 months to 30-36 months to allow adequate time to obtain quotes, review and select vendors to engineer, procure, and construct back-up facilities that meet the new requirements.
Response: The SDT tried to provide a reasonable time period and this timeframe was vetted by the industry through the comment process. No change made.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	While the standard still has some specific areas for improvement (clarity around tertiary operating facilities, delegation of operating tasks, and redundant communications), the proposed standard, on balance, will present an increased capability in reliable operations.
Response: Thank you for your support.				
Terry Bilke	Midwest ISO, Inc.	2	Abstain	We are turning the ballot over to another person and will cast our official position during recirculation.
Response: The standard is now going to go through another posting period.				

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in EOP-008-1 – Loss of Control Center Functionality.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in EOP-008-1

The SDT applied the following NERC criteria when proposing VRFs for the requirements in EOP-008-1:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VSL Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The team believes that Guideline 4 is

[2] Id. at footnote 15.

reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eight requirements in EOP-008-1. Of the eight requirements, Requirements R2 and R5 were assigned a “Lower” VRF while all of the other requirements were given a “Medium” VRF.

VRF for EOP-008-1, Requirement R1:

- FERC’s Guideline 2 **—** Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC’s Guideline 3 **—** Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the creation of a plan: EOP-005-2 for a restoration plan and EOP-008-1 for a backup plan. The VRF assigned to EOP-008-1, Requirement R1 is lower than EOP-005-2, Requirement R1. The SDT recognizes that the VRF for EOP-008-1, Requirement R1 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC’s criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to have an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a “High” VRF there should be the expectation that failure to meet the required performance “will” result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to create an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to have an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to have an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred.
- FERC’s Guideline 4 **—** Consistency with NERC’s Definition of a VRF. Failure to have an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity’s ability to effectively monitor and control the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC’s criteria for a Medium VRF. Failure to have an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.
- FERC’s Guideline 5 **—** Treatment of Requirements that Co-mingle More Than One Objective. EOP-008-1, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for EOP-008-1, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. EOP-008-1, Requirement R2 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a copy of the Operating Plan for backup functionality at each of its control locations should not have an adverse impact on the bulk power system because operations at the different locations should be essentially identical. This is mainly an administrative requirement and thus meets NERC's criteria for a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. EOP-008-1, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for EOP-008-1, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. EOP-008-1, Requirement R3 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs. However, the SDT did assign the same VRF to EOP-008-1, Requirement R4 which is a similar requirement applying to Transmission Operators and Balancing Authorities. The assignment of the "Medium" VRF was made based on the premise that failure to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center), by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. The Reliability Coordinator is always responsible for maintaining the reliability of the bulk power system regardless of the situation. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when a Reliability Coordinator fails to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center). The SDT agrees that if the Reliability Coordinator fails to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center), this failure will put the Reliability Coordinator in a position where they are not as prepared as they should be to address the situation. However, even if the Reliability Coordinator failed to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center), the Reliability Coordinator is still required to maintain control and awareness of the bulk power system. In addition, the Transmission Operators and Balancing Authorities who report to the affected Reliability Coordinator would still be expected to be operating in 'normal' mode thus providing comprehensive coverage of the bulk power system in the timeframe where the Reliability Coordinator has a problem.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a backup control center facility (provided through its own dedicated backup facility or at

another entity's control center) will impact the situational awareness of the Reliability Coordinator, and thus could affect the Reliability Coordinator's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Reliability Coordinator is required to maintain control and awareness of the bulk power system at all times. In addition, the Transmission Operators and Balancing Authorities who report to the affected Reliability Coordinator would still be expected to be operating in 'normal' mode thus providing comprehensive coverage of the bulk power system in the timeframe where the Reliability Coordinator has a problem. Therefore, the failure of a Reliability Coordinator to have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center) should not directly result in instability, separation, or cascading failures. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. EOP-008-1, Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for EOP-008-1, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. EOP-008-1, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs. However, the SDT did assign the same VRF to EOP-008-1, Requirement R3 which is a similar requirement applying to Reliability Coordinators. The assignment of the "Medium" VRF was made based on the premise that failure to have backup functionality (provided either through a facility or contracted services), by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. The Transmission Operator and Balancing Authority are always responsible for maintaining the reliability of the bulk power system regardless of the situation. For a requirement to be assigned a "High" VRF, there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when a Transmission Operator or Balancing Authority fails to have backup functionality (provided either through a facility or contracted services). The SDT agrees that if the Transmission Operator or Balancing Authority fails to have backup functionality (provided either through a facility or contracted services), this failure will put the Transmission Operator or Balancing Authority in a position where they are not as prepared as they should be to address the situation. However, even if the Transmission Operator or Balancing Authority failed to have backup functionality (provided either through a facility or contracted services), the Transmission Operator or Balancing Authority is still required to maintain control and awareness of the bulk power system. In addition, the Reliability Coordinator who 'sits' above the affected Transmission Operator or Balancing Authority would still be expected to be operating in 'normal' mode thus providing comprehensive coverage of the bulk power system in the timeframe where the Transmission Operator or Balancing Authority has a problem.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have backup functionality (provided either through a facility or contracted services) will impact

the situational awareness of the Transmission Operator or Balancing Authority, and thus could affect the Transmission Operator's or Balancing Authority's ability to effectively monitor and control the bulk power system, however violation of this requirement is unlikely to lead to bulk power system instability, separation or cascading failures. The Transmission Operator or Balancing Authority is required to maintain control and awareness of the bulk power system at all times. In addition, the Reliability Coordinator who 'sits' above the affected Transmission Operator or Balancing Authority would still be expected to be operating in 'normal' mode thus providing comprehensive coverage of the bulk power system in the timeframe where the Transmission Operator or Balancing Authority has a problem. Therefore, the failure of a Transmission Operator or Balancing Authority to have backup functionality (provided either through a facility or contracted services) should not directly result in instability, separation, or cascading failures. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. EOP-008-1, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for EOP-008-1, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in proposed EOP-005-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the update of a plan: EOP-005-2 for a restoration plan and EOP-008-1 for a backup plan. The VRF assigned to EOP-008-1, Requirement R5 is lower than EOP-005-2, Requirement R4. The SDT recognizes that the VRF for EOP-008-1, Requirement R5 is lower than the VRF for the similar requirement in EOP-005-2 which is assigned a High VRF, however the SDT and stakeholders support the Medium VRF based on NERC's criteria for VRFs. The assignment of the Medium VRF was made based on the premise that failure to update an Operating Plan for backup functionality, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to update an Operating Plan for backup functionality. While the SDT agrees that, under some circumstances, it is possible that a failure to update an Operating Plan for backup functionality may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to have an Operating Plan for backup functionality would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to update an Operating Plan for backup functionality, it would still be expected to handle the situation if it occurred. Additionally, the assignment of a Medium VRF to this requirement is consistent with the VRF assignment for Requirement R1.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to update an Operating Plan for backup functionality could directly affect the electrical state or the capability of the bulk power system, and could affect the applicable entity's ability to effectively monitor and control the bulk power system. However, violation of this

requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to update an Operating Plan for backup functionality will not, by itself, lead to instability, separation, or cascading failures.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. EOP-008-1, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for EOP-008-1, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. EOP-008-1, Requirement R6 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. EOP-008-1, Requirement R6 addresses the situation applicable entities primary and backup capabilities can't depend on each other. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did have a dependence between their primary and backup capabilities it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. EOP-008-1, Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for EOP-008-1, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. EOP-008-1, Requirement R7 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. EOP-008-1, Requirement R7 mandates testing of an applicable entity's Operating Plan for backup capability. A violation of this requirement is assigned a "Medium" VRF because, if the applicable entity did not test their Operating Plan for backup capability it is not clear that this could directly lead, without any other violations of any other requirements, to instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. IRO-010-1a Requirements R1 and R2 each address a single objective and each has a single VRF.

VRF for EOP-008-1, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. EOP-008-1, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. EOP-008-1, Requirement R8 mandates that entities provide a plan for re-establishing backup capabilities following a catastrophic failure. A failure to provide this plan does not affect the applicable entity's ability to effectively monitor and control the bulk power system. Violation of this requirement is unlikely, by itself, to lead to bulk power system instability, separation, or cascading failures, thus the assignment of a "Medium" VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. EOP-008-1, Requirement R8 addresses a single objective and has a single VRF.

Justification for Assignment of Violation Severity Levels for EOP-008-1

In developing the VSLs for the EOP-008-1 standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in EOP-008-1 meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for EOP-008-1 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines.	The most comparable VSLs for a similar requirement are for the proposed EOP-005-2, Requirement R1. Those VSLs are based on missing one element for Lower, two for Moderate, etc., which is analogous to the VSL structure for EOP-008-1, Requirement R1. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for EOP-008-1 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for EOP-008-1 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for EOP-008-1 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for EOP-008-1 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines.	The most comparable VSLs for a similar requirement are for the proposed EOP-005-2, Requirement R4. Those VSLs are based on late distribution of a plan which is analogous to the VSLs for EOP-008-1, Requirement R5. The VSLs assignments are similar between the two standards. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for EOP-008-1 Requirement R6:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for EOP-008-1 Requirement R7:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for EOP-008-1 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for 4th Draft of Standards for Backup Facilities (Project 2006-04)

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the 4th draft of the standards for Backup Facilities (Project 2006-04). Comments must be submitted by **March 8, 2010**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Backup_Facilities.html

Background Information:
The Backup Facilities Standard Drafting Team (BFSDT) has made changes to the fourth posting of EOP-008-1 based on comments received from the industry. Major changes included:

- Requirement R1, part 1.1 — Clarification of the terminology "prolonged period of time" by replacing it with "the time it takes to restore the primary control center functionality".
- Requirement R1, part 1.2.1 — Clarification of "situational awareness".
- Requirements R3 and R4 — Clarifications have been made to staffing requirements of the backup facility/functionality.
- Requirement R6 — Clarification of the term "independent" by replacing it with "do not depend on each other".
- Updates to the VSLs to conform to the latest VSL Guidelines.

The Backup Facilities Standard Drafting Team would like to receive industry comments on this standard. Accordingly, we request that you review the red line version of the standard, the VSL Guidelines, and the drafting team's justification for proposing VSL and then submit your comments on the electronic form by **March 8, 2010.**

1. Requirement R1, part 1.1: 'prolonged period of time' was replaced with 'the time it takes to restore the primary control center functionality'. Do you agree with this change? Please supply specific reasons for your comments.

   ☐ Yes

   ☐ No

   Comments:

2. Requirement R1, part 1.2.1: 'allow visualization capabilities' has been deleted thus placing the onus on situational awareness of the BES. Do you agree with this change? Please supply specific reasons for your comments.

   ☐ Yes

   ☐ No

   Comments:

3. Requirements R3 & R4: 'when control has been transferred to the backup…' was added to emphasize that operators are only required at the backup when it is in service. Do you agree with this change? Please supply specific reasons for your comments.

   ☐ Yes

   ☐ No

   Comments:

4. Requirement R6: 'can independently maintain' was replaced with 'do not depend on each other…' Do you agree with this change? Please supply specific reasons for your comments.

   ☐ Yes

   ☐ No

   Comments:

5. The SDT has made changes to the VSLs for this project based on the latest VSL guidelines. Do you agree with these changes? If not, please provide specific reasons for your comment. Do you agree with these changes? Please supply specific reasons for your comments.

   ☐ Yes

   ☐ No

   Comments:

6. Do the proposed revisions to the standard pose any new issues or questions that haven't been raised and previously addressed? Please provide specific reasons for your comment.

   ☐ Yes

   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for EOP-008-1

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

EOP-008-1 — Loss of Control Center Functionality

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards and no new or revised definitions in the proposed standard.

Compliance with Standard

EOP-008-1: Loss of Control Center Functionality	Functions That Must Comply With the Associated Requirements		
	Reliability Coordinator	Balancing Authority	Transmission Operator
R1	X	X	X
R2	X	X	X
R3	X		
R4		X	X
R5	X	X	X
R6	X	X	X
R7	X	X	X
R8	X	X	X

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard.

Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with the requirements.

EOP-008-0 is retired when EOP-008-1 goes into effect.

All requirements of EOP-008-1 will go into effect the first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

Implementation Plan for EOP-008-1

Prerequisite Approvals
There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

EOP-008-1 – Loss of Control Center Functionality

Revision to Sections of Approved Standards and Definitions
There are no proposed revisions to requirements in other already approved standards and no new or revised definitions in the proposed standard.

Compliance with Standard

EOP-008-1: Loss of Control Center Functionality	Functions That Must Comply With the Associated Requirements		
	Reliability Coordinator	Balancing Authority	Transmission Operator
R1	X	X	X
R2	X	X	X
R3	X	~~X~~	~~X~~
R4	~~X~~	X	X
R5	X	X	X
R6	X	X	X
R7	X	X	X
R8	X	X	X
~~R9~~	~~X~~	~~X~~	~~X~~

Effective Date
The effective date is the date entities are expected to meet the performance identified in this standard.

Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with the requirements.

EOP-008-0 is retired when EOP-008-1 goes into effect.

All requirements of EOP-008-1 will go into effect the first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008
6. Third posting of revised standard on March 17, 2009
7. Initial ballot posting on September 16, 2009
8. Standards Committee remanded to SDT on November 12, 2009

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 3Q10. The current draft is the fourth iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit for second attempt at initial ballot posting.	April 2010
2. Submit standard for recirculation balloting.	July 2010
3. Submit standard to BOT.	July 2010
4. Submit to regulatory authorities.	October 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.

5. **Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.2.1. Tools and applications to ensure that operating personnel have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Voice communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1 part 1.2. The Operating Process shall include at a minimum:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities do not depend on each other for the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the current year and three previous years in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the current year and three previous years, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup

functionality in force since its last compliance audit, that its primary and backup capabilities do not depend on each other for the functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Measurement M8.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's Parts (1.1 through 1.6).	The responsible entity did not have a current Operating Plan for backup functionality.
R2	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3.
R4.	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4.

R#	Lower	Moderate	High	Severe
	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Medium VRF.	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a High VRF.	
R5.	The responsible entity did not update its approved Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to the capabilities described in Requirement R1.	The responsible entity did not update its approved Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to the capabilities described in Requirement R1.	The responsible entity did not update its approved Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to the capabilities described in Requirement R1.	The responsible entity did not have evidence that its dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update its approved Operating Plan for backup functionality for more than 90 calendar days after ay change to the capabilities described in Requirement R1.
R6.	N/A	The responsible entity did not have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity did not have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity did not have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1 continuous hour but	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less 0.5 continuous hours.

R#	Lower	Moderate	High	Severe
			more than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup capability and anticipated that the loss of primary or backup capability would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish backup capability but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup capability and anticipated that the loss of primary or backup capability would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish backup capability but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup capability and anticipated that the loss of primary or backup capability would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish backup capability but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup capability and anticipated that the loss of primary or backup capability would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish backup for more than nine calendar months after the date when the functionality was lost.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008
6. Third posting of revised standard on March 17, 2009
7. Initial ballot posting on September 16, 2009
8. Standards Committee remanded to SDT on November 12, 2009

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 3Q10. The current draft is the fourth iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit for second attempt at initial ballot posting.	April 2010
2. Submit standard for recirculation balloting.	July 2010
3. Submit standard to BOT.	July 2010
4. Submit to regulatory authorities.	October 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.

Effective Date: The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ensures reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for ~~a prolonged period of~~ the time it takes to restore the primary control center functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.2.1. Tools and applications ~~that allow visualization capabilities that~~ to ensure that operating personnel have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Voice communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1 part 1.2. The Operating Process shall include at a minimum:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on ~~-~~a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that ~~can independently maintain~~ do not depend on each other for the functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup capabilities ~~can independently maintain~~ do not depend on each other for the functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the current year and three previous years in accordance with Measurement M1.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.

- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.

- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the current year and three previous years, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Measurement M5.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup capabilities ~~can independently maintain~~ do not depend on each other for the functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup capability and that anticipates that the loss of primary or backup capability would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup capability in accordance with Measurement M8.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's ~~parts~~ Parts (1.1 through 1.6)~~ or the plan does not reflect the date of its last issuance~~.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's ~~parts~~ Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's ~~parts~~ Parts (1.1 through 1.6)~~ or is not compliant with Requirement R1, part 1.5~~.	The responsible entity did not have a current Operating Plan for backup functionality.
R2~~.~~	~~The responsible entity had an Operating Plan for backup functionality available at all of its control locations but at one location it was not the current plan.~~ N/A	~~The responsible entity had an Operating Plan for backup functionality available at all of its control locations but at all locations it was not the current plan.~~ The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	~~The responsible entity had an Operating Plan for backup functionality but no version of the plan was available at all of its control locations.~~ The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	The Reliability Coordinator has ~~demonstrated that it has~~ a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	The Reliability Coordinator has ~~demonstrated that it has~~ a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has ~~demonstrated that it has~~ a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator ~~did not demonstrate that it has~~ does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3.

R#	Lower	Moderate	High	Severe
R4.	The responsible entity has ~~demonstrated that it has~~ backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	The responsible entity has ~~demonstrated that it has~~ backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Medium VRF.	The responsible entity has ~~demonstrated that it has~~ backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a High VRF.	The responsible entity ~~did not demonstrate that it has~~ does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4.
R5.	~~The responsible entity has evidence that its dated, current, in force Operating Plan for backup functionality, was reviewed and approved but it was not done in one calendar year or~~ ~~that it was~~The responsible entity did not update~~d~~ its approved Operating Plan for backup functionality for more than ~~sixty~~ 60 calendar days and less than or equal to ~~ninety~~ 70 calendar days after ~~any~~ a change~~s~~ to the capabilities described in Requirement R1.	~~N/A~~ The responsible entity did not update its approved Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to the capabilities described in Requirement R1.	~~The responsible entity has evidence that its dated, current, in force Operating Plan for backup functionality, with evidence of its last issue, was reviewed and approved but it was not done in two calendar years or more or that it was updated more than ninety calendar days after any changes to the capabilities described in Requirement R1.~~ The responsible entity did not update its approved Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to the capabilities described in Requirement R1.	The responsible entity did not have evidence that its dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update its approved Operating Plan for backup functionality for more than 90 calendar days after a~~n~~y change~~s~~ to the capabilities described in Requirement R1.
R6.	N/A	~~N/A~~ The responsible entity did not have primary and backup capabilities that do not depend on each other for the functionality required to maintain	~~N/A~~ The responsible entity did not have primary and backup capabilities that do not depend on each other for the functionality required to maintain	The responsible entity did not ~~demonstrate that its~~ have primary and backup capabilities ~~can independently maintain~~ that do not depend on each

R#	Lower	Moderate	High	Severe
		compliance with Reliability Standards applicable for the entity that have a Lower VRF.	compliance with Reliability Standards applicable for the entity that have a Medium VRF.	other for the functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.
R7.	~~The responsible entity has annually tested its Operating Plan for backup functionality, but one of the following occurred:~~ ~~1) the demonstration was for less than two continuous hours,~~ ~~2) it failed to demonstrate that the transition time period is less than or equal to two hours, or~~ ~~3) test results were not documented.~~ The responsible entity conducted an annual test of its Operating Plan for backup functionality but it did not document the results. ~~test did not assess the~~ OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	~~The responsible entity has annually tested its Operating Plan for backup functionality, but two of the following occurred:~~ ~~1) the demonstration was for less than two continuous hours,~~ ~~2) it failed to demonstrate that the transition time period is less than or equal to two hours, or~~ ~~3) test results were not documented.~~ OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	~~The responsible entity has annually tested its Operating Plan for backup functionality, but all three of the following occurred:~~ ~~1) the demonstration was for less than two continuous hours,~~ ~~2) it failed to demonstrate that the transition time period is less than or equal to two hours, and~~ ~~3) test results were not documented.~~ The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	~~The responsible entity did not annually test its Operating Plan for backup functionality.~~ The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less 0.5 continuous hours.
R8.	The responsible entity ~~that has~~ experienced a loss of ~~their~~ its primary or backup capability and ~~that anticipates~~ anticipated that the loss of primary or backup capability would last for more than six calendar months ~~has provided evidence that~~and ~~a plan has been submitted~~ provided a plan to its Regional	~~N/A~~ The responsible entity experienced a loss of its primary or backup capability and anticipated that the loss of primary or backup capability would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish backup capability but the	~~N/A~~ The responsible entity experienced a loss of its primary or backup capability and anticipated that the loss of primary or backup capability would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish backup capability but ~~it~~the	The responsible entity ~~that has~~ experienced a loss of ~~their~~ its primary or backup capability and ~~that~~ anticipate~~s~~d that the loss of primary or backup capability would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish

R#	Lower	Moderate	High	Severe
	Entity showing how it will re-establish backup capability but ~~it~~ the plan was submitted ~~in~~ more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	plan was submitted in more than eight calendar months but less than or equal to nine calendar months ~~of~~after the date when the functionality was lost.	backup for more than nine calendar months after the date when the functionality was lost.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
February 4–March 8, 2010

Now available at: http://www.nerc.com/filez/standards/Backup_Facilities.html

Project 2006-04: Backup Facilities
The Backup Facilities Standard Drafting Team is seeking comments on proposed standard EOP-008-1 — Loss of Control Center Functionality **until 8 p.m. Eastern on March 8, 2010**.

An initial ballot for EOP-008-1 was conducted from September 16–28, 2009. Instead of proceeding to recirculation ballot, the proposed standard has been reposted for industry review and comment. The drafting team revised the standard based on industry comments submitted during the initial ballot, and the team has posted its consideration of those industry comments. The drafting team is requesting stakeholders to review the red-line version of the standard, the VSL Guidelines, and the drafting team's justification for the proposed VSLs (all of which are posted on the project page).

Instructions
Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Next Steps
The drafting team will draft and post responses to comments received during this period. The drafting team will also determine whether to post the standard for an additional comment period or seek approval from the Standards Committee to proceed to balloting.

Project Background
The purpose of the standard is to ensure continued reliable operations of the bulk power system in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

Applicability of Standards in Project
Reliability Coordinators
Transmission Operators
Balancing Authorities

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Individual or group. (34 Responses)
Name (22 Responses)
Organization (22 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
Question 1 (34 Responses)
Question 1 Comments (34 Responses)
Question 2 (34 Responses)
Question 2 Comments (34 Responses)
Question 3 (34 Responses)
Question 3 Comments (34 Responses)
Question 4 (33 Responses)
Question 4 Comments (34 Responses)
Question 5 (27 Responses)
Question 5 Comments (34 Responses)
Question 6 (31 Responses)
Question 6 Comments (34 Responses)

Individual
Michael R. Lombardi
Northeast Utilities
Yes
Yes
Yes
Yes
Yes
No
Group
Upper Peninsula Power Company and Wisconsin Public Service Corp
Tom Webb
Yes
Wisconsin Public Service Corp (WPSC) supports the change the new verbiage provides clarity lacking in the previous revision.
No
Wisconsin Public Service Corp agrees with the removal of the phrase “allows visualization of capabilities” but disagrees with the addition of the phrase “situational awareness of the BES.” “Situational awareness of the BES” is neither a defined term nor is it a requirement for a primary control center. Using this term would result in the request for interpretations, inconsistent enforcement, or rule making through enforcement. To address this issue the Wisconsin Public Service Corp suggest the verbiage of R1.1.2 be revised to state: "1.2.1. Tools and applications that ensures reliable operations of the BES."
Yes
The Wisconsin Public Service Corp supports the clarification described in R4. We suggest removing the phrase “of two weeks or less.” The length of allowable outage regardless if it is planned or unplanned has the same effect on the BES and should be treated consistently in R8.

No
The phrase “do not depend on each other for” is no less ambiguous than “can independently maintain” therefore Wisconsin Public Service Corp does not support this change. Furthermore the required level of redundancy and separation can not be adequately defined until the scope (radius) of damage to the primary control center is defined and if other single failure (n-1) scenarios must be considered. Wisconsin Public Service Corp suggests that the N-1 scenario include, and be limited to, the primary control center and its energy management system. Other systems, communication systems and communication rooms outside of the rooms that house primary control center or primary energy management system would be assumed to be intact and fully operable. Failure to first define the level of assumed damage will result in the request for interpretations, inconsistent enforcement, and rule making through enforcement.
No
R1, R2, and R8 are documentation issues not a functionality issue. Therefore the maximum severity should be no more than low. With regards to R5, this is a documentation issue related to the control centers. It is not a functionality issue. Therefore it is hard to conceive of a documentation issue that could have a significant adverse affect on the reliability of the BES. Furthermore the materiality of the omitted updated material must be included in any discussion of risk factors. For example, failure to include and updated phone number in the plan documented has little or no affect on the reliability and safety of the BES. Whereas, outdated instructions on how to establish data communication would have more significance. Furthermore it is hard to conceive of a scenario of how an annual review, regardless of the definition of annual, overdue by one day could significantly affect the reliability of the BES especially if that annual review did not identify any changes. As R5 deals with documentation and not functionality, violations of R5 should be low. With regards to R7, the failure to test or surveil a function should only be considered a high or severe issue if the lack of surveillance failed to assure or could have failed to assure an adequate response to a real event.
Yes
With regards to R7, additional verbiage is required to describe an acceptable functionality test. Does a functionality test require the entity to control BES assets from the backup control center or can operators monitor the BES from the backup control center while the primary control center continues to control and monitor the BES. If the functionality test requires the entity to control from the backup control center; is there a level or percentage of control required? Wisconsin Public Service Corp suggests that monitoring the BES in parallel with the primary control center provides adequate demonstration of functionality. Failure to define an adequate functional test will result in the request for interpretations, inconsistent enforcement, and rule making through enforcement. Wisconsin Public Service Corp also request the standard committee explain the safety and reliability significance to the BES of the 2 hour time limit provided in R 1.5 and how lengthening this time period would have a discernable adverse affect on the reliability or safety of the BES. Furthermore; please clarify, would an entity be in violation if they can’t get their back-up site fully functional within two hours for any reason? For example, R6 states: "primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards." To meet this statement, the entity must design a primary and backup control centers that are separated and redundant enough to survive an assumed initiating event. The level of damage should be specified by the drafting teaming, or lacking guidance by the drafting team by the entity itself. If the actual event is more severe than the assumed event and the backup control center is not up and running in two hours, is this a violation of the standard? To assure a consistent and non-capricious enforcement of the standard, these areas need to be further clarified by the drafting team.
Individual
Lee Pedowicz
NPCC
Yes
Yes
Yes
Yes
Yes
No

Group
ISO/RTO Standards Review Committee
Ben Li
Yes
Yes
Yes
We agree with the changes but suggest rewording that part pertaining to compliance to reliability standards as follows: Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for fulfilling its functional obligations. To avoid requiring a tertiary facility, a backup facility is not required during: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]
Yes
No
AESO would note that it does not comment on VSLs as VSLs are a Canadian Provincial matter. (1) R6: We do not agree with determining VSLs according to the VRF levels. A VRF represents the level of reliability impact on the bulk electric system if the requirement is not met; whereas a VSL represents the extent to which a requirement is not met. The latter is independent of the former. (2) R7, Medium VSL: The condition before the “OR” is missing.
Yes
(1) R1: Entities cannot “ensure” reliable operations of the BES. They can operate the BES within their footprint to contribute to interconnected system reliability in accordance with their responsible functionalities. We suggest “ensures reliable operations of the BES” be changed to” “continues to meet their functional obligations”. (2) We think that this requirement puts the BA at a difficult and even non-compliant situation since the BA as a functional entity is not required to have access to the transmission conditions on the BES. Similarly, the TOP may not have access to any generation-load-interchange balance information. Further, we suggest to replace “operating personnel” with “System Operator” – a defined term for operators at the RC, BA and TOP control centres to which this EOP standard applies. The proposed wording of 1.2.2 would thus read: Tools and applications that to ensure that the RC, BA and TOP have the capability to meet their respective functional obligations. (3) R1.2.5: This is not required since CIP-002-2 R1 already requires a Critical Asset Identification Method which includes in R1.2.1, the Control centers and backup control centers performing the functions of the entities listed in the Applicability section of that standard. (4) R1.2 seems to be a requirement to only have a descriptive list, i.e. - a document. If the measure of compliance to R1.2 is the presence of a document, then the subsequent sub requirements, 1.2.1, 1.2.2, 1.2.3, 1.2.4 1.2.5 should be reorganized as a list and not distinct sub requirements since these are not individually measured for compliance to R1.2. (5) R1.6.2 requires during the 2 hour period for transition to the backup center, the Operating Process must include “Actions to manage the risk to the BES…”. It is unclear what “risk to the BES” must have actionable operations. If they include VSLs, IROLs and RSG requirements, all requiring action under the 2 hour period, then this may require a redundant parallel operation during the transition period since a neighboring BA, TOP, or RC may not have control to take “Action”. We do not believe that is the intent, however, it is unclear what capabilities are required to be compliant to R1.6.2 during the 2 hour transition to the backup facility. (6) R5 and R7: The word annually leaves room for interpretation. Where annual reviews or testing are required, annually can mean “an event that occurs yearly” which can results in two events occurring within a month of the New Year. To add clarity to meeting the intent of having reviews/testing done periodically within a 12 month time frame, we recommend that the drafting team replace annual test/review requirements with “test/review once each calendar year but in no event can the duration between test/review exceed 18 months”. This would allow entities to have flexibility within a calendar year to push back review/testing by 1-2 Quarters to address, for example, other business needs, but would not allow delays that result in reviews/testing more than 18 months apart. (7) R6: The way this requirement is worded can be ambiguous. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain…” The word capability may mean the capability of the responsibility or the capability of the functionality, and hence the “each other” could be interpreted as the responsible entity or the capability functionality. If this is meant to be the functionality, we suggest R6 be revised to provide clarity, such as: Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other to maintain… (8) R8: We suggest to replace the phrase “functionality is lost” with the loss of functionality is discovered” since the loss of functionality may not be known until it is checked periodically.
Group

PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Yes
Yes
No
Individual
Kelly Wolfe
Black Hills Power
Yes
Yes
Yes
No
The phrase “primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards” is unclear and implies a requirement of redundant facilities well outside of the control center. For example, a loss of “capability” may be considered to have occurred a) in the event of a loss of SCADA communications caused by equipment failures outside of the control center or b) loss of RTU functionality within a substation. In this case, a “primary capability” (i.e. EMS tie line monitoring obtained from a failed substation RTU or a failed communications circuit) depends on a “backup capability” (the same RTU and/or communications circuit) which are both removed from the control center. As written, the Standard seems to require redundant communications and RTUs since a “loss of capability” would exist in these cases. I suspect that the Standard is actually intended to only provide redundancy of equipment located at the control center facility but, as written, seems to actually require redundancy of equipment far away from the control center. This is too broad of a scope for the implied intent of this Standard and should be re-written
Yes
Comments applicable to the overall Standard: The phrase “loss of control center functionality” is a fundamental and critical term which determines compliance to this Standard. However, there is no description or definition of how auditors or Functional Entities would determine if “loss of control center functionality” occurred. For example, would a “loss of control center functionality” occur if one or many non-redundant SCADA communications lines to critical substation(s) became non-functional? In order to prevent future compliance enforcement issues, we request specific clarity on these terms within the Standard itself or the Glossary of Terms. === Comment specific to R2: R2 states . . . “shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality.” The term “shall have a copy” may imply a physical hard copy. We request modifying the language in the Standard to allow electronic access to the same Operating Plan. One proposal would be to change “shall have a copy of” to “shall have access to”. === Comment specific to R5 part 5.1: R5 reads “An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1. The phase “any changes in capabilities described in Requirement R1” is extremely broad and would seem to cause non-compliance for minor, insignificant changes such as SCADA system applications or version changes. We offer the following alternative phrase to prevent such issues- “any changes in capabilities which would impact the Operating Plan described in Requirement R1”.

=== Comment specific to R8: Requirement R8 refer to a "loss of primary or backup capability" but there is no definition or description of what constitutes a loss of "capability" such as a single communication outage or perhaps a partial loss of capability due to an EMS software glitch that would exist at both primary and backup facilities. We request that the Standard clarify how the Functional Entity would determine or define a loss of "capability".
Individual
Brenda Lyn Truhe
PPL Electric Utilities
Yes
Yes
Yes
Yes
Yes
No
The changes are appropriate clarifications.
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
The change makes it obvious that a backup plan is required for any failure of the primary control center. The previous statement "prolonged period" provided a loop hole meaning that not all primary control center failures require a backup plan, especially short duration ones.
No
Cannot find a historic reason why "visual capabilities" is being removed. Data and voice communications along with visual capabilities are all required for situational awareness of the BES. If SDT is considering making changes to 1.2 consider this example: 1.2. A summary description of the elements required to support the backup functionality and to provide operating personal situational awareness capabilities and operational control of the BES. These elements shall include, at a minimum: 1.2.1. Tools and applications that allow visualization capabilities. 1.2.2. Tool and applications for continuous Data updating and exchange. 1.2.3. Tools and applications to maintain viable Voice communications. 1.2.4. Power source(s). 1.2.5. Physical and cyber security. Data, voice and visual capabilities are three basic elements required for situational awareness for operating personnel. Removing 'visual', while leaving the voice and data portion of situational awareness does not make sense. (Situational awareness: to detect and interpret information and events and integrate the impact of your own actions in a dynamic environment)
Yes
Sometimes stating the obvious removes all doubt. Without the addition of this statement, it could be perceived that when control is transferred to a backup facility, qualified staff would not be required. This also enhances M3 and M4 measures. This clarifies that qualified staff are required to operate the backup facility when it is in control.
Yes
This does improve the statement and Measure R6 to more clearly indicate that the backup facility cannot be dependent on the primary facility.
No
Changes to R1 are fine Changes to R2 new VSL definitions are clearer. Could argue that the two VSL's be Lower and Moderate instead of Moderate and Severe but have no justification for this at this time. Change to R3 coincides with revision to Requirement R3 – fine. Change to R4 coincides with revision to Requirement R4 – fine. Changes to R5 are fine. R6 – Not sure why entities would have different VRF for the same requirement and therefore placed in different VSLs? R7- VSL as written focus too much on time lines, not whether the run was successful, or documented or done annually. VSL Lower – Did not document results of annual test, transition period or successful run greater than 2 hours. VSL Moderate – Documented all, ran successful, but did not exceed 2 hours. VSL High – Documented all, ran successfully but test not done annually. VSL Severe –Combination of any two of the other two VSL's R8 – Instead of time line windows of reporting for each VSL, create specific failures. VSL Lower – Failed to

identify loss will be greater than 6 months VSL Moderate – Failed to provide a plan when loss expected to exceed 6 months. VSL High – Failed to provide a plan within 6 months of failure. VSL Severe -
No
As answered in individual questions.
Individual
Frank Cumpton
BGE
Yes
BGE agrees with the proposed clarification of this statement.
Yes
BGE agrees this change is acceptable.
Yes
BGE agrees this change is a necessary clarification.
Yes
BGE agrees with the proposed clarification.
Yes
BGE agrees with the changes to the VSLs.
No
It appears to be inconsistent that R4 requires obtaining a tertiary facility for planned outages lasting over 2 weeks, but that for forced outages of a primary or back up control center the only requirement, per R8, is to provide a plan within 6 months showing how the entity will re-establish backup capability but with no time-frame requirements.
Individual
Luke Weber
We Energies
Yes
R1 applies to "Each RC, BA, and TOP and requires each to ensure 'reliable operations of the BES'." No single entity can ensure the reliability of the BES. Rather these entities ensure the reliability of the BES working together fulfilling their functional obligations. We suggest "ensures reliable operations of the BES" be changed to "continues to meet their functional obligations."
No
The term “situational awareness” is subject to interpretation. Since R3 and R4 already specify backup control center capability “… that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a (Balancing Authority and Transmission Operator’s) primary control center functionality …” it recommended that R1.2.1 be eliminated from the standard.
Yes
Yes
Suggest adding the words "applicable to the Functional Entity" at the end: “Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards applicable to the Functional Entity.”
No
The VSLs for R1 should state clearly whether R1.2 is considered one requirement or several requirements. The VSLs for R6 should not be more severe than the VRFs for the applicable Reliability Standards. These VSLs are also tricky to read because they employ double negatives. Recommend wording such as “The responsible entity has primary and backup capabilities that depend on each other for the functionality required to maintain compliance with Reliability Standards applicable to the entity that have a Lower VRF.”
Yes
R5.1 is overly broad in specifying “any changes in capabilities described in R1” and overly aggressive in terms of the 60 day requirement to update and approve the operating plan. Recommend an annual requirement to review, update and approve the plan, and eliminating the verbiage "any changes in capabilities described in R1."
Individual
Joylyn Faust
Consumers Energy
Yes

No
Neither statement is terribly efficient. Both leave ambiguity in the standard. Suggested verbiage would include: “Tools and applications to ensure similar functionality as available at the Primary Control Center."
Yes
Yes
Individual
James Sharpe
South Carolina Electric and Gas
Yes
Yes
Yes
No
We suggest adding the three (3) phrases (in quotes) in the sentence for additional clarification: Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup “control center” capabilities that do not depend on each other “or any common capability” for the functionality required, “as mentioned in R1, section 1.2”, to maintain compliance with Reliability Standards
No
We suggest changing the VSLs for R5 to have a range of 30 calendar days in each of the Low, Moderate and High columns as opposed to 10 calendar days. These plans are reviewed annually and this time frame seems to line up better. Also, the VSLs for R5 do not parallel Section 5.1 of R5. The key part of Section 5.1 is “An update and approval of the Operating Plan”. The VSLs currently do not contemplate reapproving the plan. An alternative solution would be to separate Section 5.1 into a unique requirement for “update” and 5.2 unique requirement for “approval”. We also suggest making conforming changes to the VSLs for requirement 6 as noted in Question 4. For clarification in requirement 1 the VSL talks about "requirement's Parts." Is this the same thing as subrequirements? If not, is Parts a defined term (hence the capitalization)?
Yes
In the context of R1, section 1.2, how much redundancy is required? Does every RTU require two completely independent communication circuits, one to the primary and one to the backup control center? We suggest that the drafting team draft language which is much more specific in defining the redundant requirement by only the control center and its associated and concentrated data paths, e.g., something like “the backup center shall not be dependent upon any capability contained within the primary control center”. We believe that silence on the issue of required levels of redundancy down to the detail level including RTUs or communication circuits will cause serious and unnecessary conflicts with the compliance function. The proposed revisions to R3 and R4 should have also included clarifying language to address the issue of whether or not tertiary facilities are required in the event of a planned outage of the primary or secondary facility in excess of two weeks. The SDT’s responses to previous comments on this issue are inadequate in that they are essentially providing an interpretation that is based upon the SDT’s own expectations and assumptions and which has no foundation in anything written in the proposed standard. We therefore suggest adding language similar to the SDT response to previous comments in these requirements. Our suggested wording would read “If a planned outage is expected to take more than the two weeks the affected entity shall develop an acceptable plan with their Regional Entity”. R5.1: We suggest adding the word “functional” in front of the word "Capabilities".
Individual
Ralph F Meyer
The Empire District Electric Company
Yes
This provides more clarity.
Yes

Yes
Yes
Yes
No
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
Yes
The MRO supports the change the new verbiage provides clarity lacking in the previous revision.
No
The MRO agrees with the removal of the phrase “allows visualization of capabilities” but disagrees with the addition of the phrase “situational awareness of the BES.” “Situational awareness of the BES” is neither a defined term nor is it a requirement for a primary control center. Using this term would result in the request for interpretations, inconsistent enforcement, or rule making through enforcement. To address this issue the MRO suggest the verbiage of R1.2.1 be revised to state: "1.2.1. Tools and applications that ensures reliable operations of the BES."
Yes
The MRO supports the clarification described in R4. We suggest removing the phrase “of two weeks or less.” The length of allowable outage regardless if it is planned or unplanned has the same effect on the BES and should be treated consistently in R8.
No
The phrase “do not depend on each other for” is no less ambiguous than “can independently maintain” therefore the MRO does not support this change. Furthermore, the required level of redundancy and separation can not be adequately defined until the scope (radius) of damage to the primary control center is defined and if other single failure (n-1) scenarios must be considered. The MRO suggests that the N-1 scenario includes, and should be limited to, the primary control center and its energy management system. Other systems, communication systems and communication rooms outside of the rooms that house primary control center or primary energy management system would be assumed to be intact and fully operable. Failure to first define the level of assumed damage will result in the request for interpretations, inconsistent enforcement, and rule making through enforcement.
No
R1, R2, and R8 are documentation issues not a functionality issue. Therefore the maximum severity should be no more than moderate. With regards to R5, this is a documentation issue related to the control centers. It is not a functionality issue. Therefore it is hard to conceive of a documentation issue that could have a significant adverse affect on the reliability of the BES. Furthermore the materiality of the omitted updated material must be included in any discussion of risk factors. For example, failure to include and updated phone number in the plan documented has little or no affect on the reliability and safety of the BES. Whereas, outdated instructions on how to establish data communication would have more significance. Furthermore it is hard to conceive of a scenario of how an annual review, regardless of the definition of annual, overdue by one day could significantly affect the reliability of the BES especially if that annual review did not identify any changes. As R5 deals with documentation and not functionality, violations of R5 should be low. With regards to R7, the failure to test or surveil a function should only be considered a high or severe issue if the lack of surveillance failed to assure or could have failed to assure an adequate response to a real event.
Yes
1. What is the significance of the two hours in R1.5? 2. Is it the intention to find the entity in violation if they can’t get their back-up site fully functional within two hours for any reason? 3. We are concerned that the term “backup capabilities” has not been clearly defined or explained in the Standard. It is used in R6 and in R8. We feel that R6 should be changed to read: “Each RC, BA and TOP shall have primary and backup functionality, as defined in R4, that do not depend on each other.” We recommend that R8 should replace the word capability with functionality.
Individual
Edwin Thompson
Consolidated Edison Co. of New York
Yes

No
It is unrealistic to assume that the RC, TOP, and BA will maintain “situational awareness” without “visualization capabilities”. In fact, the 2003 Blackout Report, Recommendation 22 directly addressed this topic. It stated “A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities. In addition, the failure of FE’s control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO’s incomplete tool set and the failure to supply its state estimator with correct system data on August 14 contributed to the lack of situational awareness. The need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations”. It is not understood how an entity will demonstrate "situational awareness" without some type of visualization tool; whether their own, or another entities as stated in R3? The SDT should consider re-phrasing the sentence to read "Tools and applications with sufficient visualization capability to ensure situational awareness of the BES".
Yes
No
The language can be clarified by stating “…..shall have independent primary and backup capabilities and functionalities required to ….” The term “do not depend on each other” should be removed since its meaning is vague.
Yes
No
Group
NPCC Regional Standards Committee
Guy V. Zito
Yes
Yes
Yes
Yes
Yes
Yes
NPCC RSC participating members suggest that “ensure” should not be used in the Standard. The use of “ensure” implies a guarantee in words, rather than actions.
Group
Electric Market Policy
Jalal Babik
Yes
Yes
Yes
No
Yes
Yes

The proposed revisions to R3 and R4 should have also included clarifying language to address the issue of whether or not tertiary facilities are required in the event of a planned outage of the primary or secondary facility in excess of two weeks. The SDT's responses to previous comments on this issue are inadequate in that they are essentially providing an interpretation that is based upon the SDT's own expectations and assumptions and which has no foundation in anything written in the proposed standard. We therefore suggest adding language similar to the SDT response to previous comments in these requirements. Our suggested wording would read "If a planned outage is expected to take more than the two weeks the affected entity shall develop an acceptable plan with their Regional Entity.
Individual
Michael Ayotte
ITC Holdings
No
The modification made to address the comments loses sight of the intent which is that you must be prepared for the loss of your primary control for varying lengths of time. Suggest the following language as an alternative: "The location and method of implementation for providing backup functionality during the period of the time that the primary control center functionality is unavailable."
Yes
None
Yes
None
Yes
None
No
Suggest the following re-wording of Requirement 6 for clarity and alignment with R4: "Each RC, BA and TOP shall have primary and backup functionality, as identified in R3 and R4, which are not dependent on each other." In Requirement 8, suggest the following re-wording to align with R3 and R4: replace the word "capability" with "functionality".
Individual
Richard Kafka
Pepco Holdings, Inc.
Yes
Yes
Yes
Yes
Yes
No
Individual
Darryl Curtis
Oncor Electric Delivery LLC
Yes
Yes
Yes
Yes

Yes
No
Individual
Todd Lietz
Seattle City Light
Yes
Yes
Yes
Yes
Yes
Yes
1. The term annual is used in requirement R5 and R7. This term need to be defined as there are many interpretations of this as it is defined in commom dictionaries. Does this mean every calendar year, every 365 days, 12 months, or 13 months (as supposedly used by WECC for CIP)? Entities should not have to rely on their definition matching that of an auditor. I would suggest a defintion of "every calendar year not to exceed 15 months between occurances". 2. Requirement R1.3 discusses the process for maintaining functionality of backup facilities as being consistent with the primary facility. Does this imply they must have the exact same functionality? Or sufficient functionality for reliable BES operation?
Individual
Jon Kapitz
Xcel Energy
Yes
No
Comments: what tools constitute adequate situational awareness? Is there a reference or another standard that would define this?
Yes
Yes
None
none
Group
Bonneville Power Administration
Denise Koehn
Yes
Yes
Yes
Yes
No

Suggest reordering the sentences in VSL-R4 to put what they “did not” do prior to the phrase “when control has been transferred to the backup functionality location …”. There appears to be no difference between Lower, Moderate and Severe except the reference to VRF. But the R4 standard Risk Factor is Medium risk. It appears to be trying to refer to Standards other than EOP-008 for functionality issues, but there is no list … just ANY standards as applicable. R7 – Suggested Revisions: Lower = Test did not asses the transition and implementation times... remove the “OR”; Moderate = no documentation or test less than 2 hours...; High = Test was less than 1 hour; Severe = NO annual test or less than 0.5 hrs.
Yes
Suggest some revisions to R5/R1 linkage regarding changes in capabilities. (a voice circuit path change transparent to the System operator is not a capability change. i.e. - A Control Center site change or Physical access would be considered a capability change).
Individual
Scott Barfield (behalf of Wayne Pourciau)
Georgia System Operations Corporation
Yes
Yes
Yes
No
Instead of "primary and backup capabilities do not depend on each other" is would read better for consistency and clarity "primary and backup functionalities do not depend on each other". The same goes for R5.1 and R8 and the associated measures where the word "capabilities" was used.
No comment.
No
Group
FirstEnergy
Sam Ciccone
Yes
Yes
Yes
While we agree with the change to emphasize that operators are only required at the backup facility when it is in service, upon further reflection we question the need to specify that certified staff are required in requirements R3 and R4, respectively: "staffed with certified Reliability Coordinator operators" and "staffed by applicable certified operators". The requirement for staffing with certified operators is contained in PER-003 which makes no distinction between primary and backup control centers. Adding this certification language to this standard essentially duplicates the requirement in PER-003. In addition, the delegation of a task requires comparable certification for those performing that task and the NERC Standards Committee is working to document this in the NERC Rules of Procedure. Therefore, we believe these statements are redundant to PER-003 and suggest they be removed.
Yes
FE supports this change and thanks the SDT for incorporating our suggested change.
Yes
Yes
Overall FE supports the Draft 5 version of the EOP-008-1 standard. Additionally, we offer the following suggestions: 1. We believe the SDT should replace the phrase "backup capabilities" with "backup functionality" in Requirements R6 and R8. Since the title of this standard is "Loss of Control Center Functionality", and since other requirements in the standard use the phrase "backup functionality", the use of "functionality" should be consistent throughout the standard. 2. FE has not previously raised the question related to certified operators in R3 and R4. See our response to Question 3. We would appreciate the drafting team's perspective and consideration of our comment. Regarding the "Regional Entity" mentioned in R8 and Sec. D1.1, we assume this to mean organizations such as FRCC, RFC,

SERC, etc. Although a minor issue, we note that this capitalized term is not defined in the NERC Glossary or the latest version of the Function Model (Ver. 5). Additionally, there seems to be a move afoot in project 2010-08 "Functional Model Glossary Revisions" to deemphasize the Regional Entity since it was not contained within the SAR scope of that project. In reviewing the project 2010-08 scope, it seems implied to FE that the Compliance Enforcement Authority and the Reliability Assurer would be potential replacements for the term Regional Entity throughout the NERC reliability standards. We encourage this drafting team to better understand the vision of using the CEA and RA within the standards and consider their use over the RE as stated in R8.
Group
Midwest ISO Standards Collaborators
Jason L. Marshall
Yes
Yes
Yes
No
We do not see the need for this change but can accept it if it will help others to support the standard.
Yes
We have identified a few issues that still remain in the standard. (1) In R1, the requirement applies to “Each RC, BA, and TOP and requires each to ensure “reliable operations of the BES”. No single entity can ensure the reliability of the BES. Rather these entities ensure the reliability of the BES working together fulfilling their functional obligations. We suggest “ensures reliable operations of the BES” be changed to” “continues to meet their functional obligations”. (2) R1, Part 1.2.5 is redundant to the CIP standards because CIP-002 requires an entity to evaluate all of their assets which would include the backup control center/functionality. (3) R1, Part 1.2.1 implies the BA has situational awareness of the BES. Per the functional model, the BA does not see most of the BES except tie line flows, generator outputs and load. This should reflect that the purpose is for the entities to fulfill their functional obligations. (4) The wording “location providing backup functionality” in R2 could be construed to create a de facto requirement to have a backup control center. (5) The wording of R3 should be improved. It essentially makes this requirement dependent on every other RC requirement in every other standard. We suggest the wording should be changed to “Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity’s control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for fulfilling its functional obligations.” (6) The first and fifth bullets under Data Retention create an obligation to retain data for longer than the 3-year audit cycle (“current year and three previous years”). At the end of the current year, four years of data would have to be maintained. We suggest making this a simple sliding three year requirement.
Group
SERC OC Standards Review Group
Jim Case
Yes
Yes
Yes
No
We suggest adding the three (3) phrases (in quotes) in the sentence for additional clarification: Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup “control center” capabilities that do not depend on each other “or any common capability” for the functionality required, “as mentioned in R1, section 1.2”, to maintain compliance with Reliability Standards.
No
We suggest changing the VSLs for R5 to have a range of 30 calendar days in each of the Low, Moderate and High columns as opposed to 10 calendar days. These plans are reviewed annually and this time frame seems to line up better. Also, the VSLs for R5 do not parallel Section 5.1 of R5. The key part of Section 5.1 is “An update and approval of the Operating Plan”. The VSLs currently do not contemplate reapproving the plan. An alternative solution

would be to separate Section 5.1 into a unique requirement for “update” and 5.2 unique requirement for “approval”. We also suggest making conforming changes to the VSLs for requirement 6 as noted in Question 4.
Yes
In the context of R1, section 1.2, how much redundancy is required? Does every RTU require two completely independent communication circuits, one to the primary and one to the backup control center? We suggest that the drafting team draft language which is much more specific in defining the redundant requirement by only the control center and its associated and concentrated data paths, e.g., something like “the backup center shall not be dependent upon any capability contained within the primary control center”. We believe that silence on the issue of required levels of redundancy down to the detail level including RTUs or communication circuits will cause serious and unnecessary conflicts with the compliance function. The proposed revisions to R3 and R4 should have also included clarifying language to address the issue of whether or not tertiary facilities are required in the event of a planned outage of the primary or secondary facility in excess of two weeks. The SDT’s responses to previous comments on this issue are inadequate in that they are essentially providing an interpretation that is based upon the SDT’s own expectations and assumptions and which has no foundation in anything written in the proposed standard. We therefore suggest adding language similar to the SDT response to previous comments in these requirements. Our suggested wording would read “If a planned outage is expected to take more than the two weeks the affected entity shall develop an acceptable plan with their Regional Entity”. R5.1: We suggest adding the word “functional” in front of the word “Capabilities.
Individual
Jason Shaver
American Transmission Company
Yes
Yes
Yes
Yes
Yes
ATC has raised the following concerns during previous commenting periods but they have not been adequately addressed by the drafting team. We believe that our concerns identify a major gap within the standard which must be addressed prior to balloting. ATC believes that the drafting team needs to drop the term “backup capabilities” used in requirements 6 and 8. Background information: Requirement 1.2 states that entities must have a summary description of the elements required to support the “backup functionality”. Requirements 1.2.1 through 1.2.5 identify the specific elements required to support “backup functionality”. Requirement 4 requires entities to “have “backup functionality” … that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a BA’s and TOP’s primary control center functionality respectively.” Requirement 6: Requirement 6 introduces a new term “backup capabilities” which we believe is attempting to reference Requirement 4 (R4) but could also be used by an auditor to expand the functionality requirements identified in R4. The drafting team should replace the term “backup capabilities” with the term “backup functionality” in order to strengthen this requirement’s ties to Requirement 4. Suggested Modification: Each RC, BA and TOP shall have primary and backup functionality, as identified in R4, which are not dependent on each other. We believe that our suggested modification achieves the goal of the requirement but also limits the ability of an auditor to expand the requirement. If the drafting team disagrees with our modification then we believe that they must specify which capabilities do not have to be dependent. Requirement 8: Similar to our concerns with proposed requirement 6 the drafting team uses the term “capabilities” but does not specify what it means. Suggested Modification: Each RC, BA and TOP that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more then six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality. We believe that our suggestion ties back appropriately to requirements 1.2 and 4, which identify what functionality has to be lost in order to trigger this requirement.
Group
Southern Company Transmission
JT Wood
Yes

Yes
More definition of the term “situational awareness” would be helpful
Yes
Yes
Yes
Recommend wording change for VSL R6 to read “The responsible entity has primary and backup capabilities that depend on each other for the functionality required to maintain…” There seems to be a discrepancy between R6 which has a VRF of Medium and the VSL Table references which has lower and high as well as medium. R7 Moderate VSL appears to be missing a critical paragraph before the “OR”. R7 Severe appears to be missing a “than” before “0.5 continuous hours”.
Yes
• R1.5 It is recommended that the timing associated with the transition period required in 1.5 be included into 1.6 as part of the Operating Process that is required there. Defining the existence of a "transition period" does nothing to improve reliability unless its tied to the actions of the Operating Process. Recommend R1.6 be changed to the following and R1.5 be eliminated (changes to SDT version shown in italics): "An Operating Process describing the actions (activities and expected time to completion) to be taken during a transition period of less than or equal to two hours between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1 part 1.2……" • In R3 and R4, add the word "normally" as shown to the phrases "…for maintaining compliance with all Reliability Standards that normally depending on…" • Recommend for emphasis and logical flow of the EOP-008 Standard, that requirement R6 which established requirement for independence of primary and be made R1 and then perhaps follow that with R3 and R4 being made R2 and R3 respectively. • The term "capabilities" in R6 may be clarified and avoid future questions or interpretation requests if it references the elements identified in R1.2. For example: "…shall have primary and backup capabilities as described in R1.2 that do not depend on each other….." • In R7, what is the measurable expectation of "demonstrates" - actually performing all control, monitoring, alarming, data movement, voice communications, etc. exclusively from the backup facility for the whole two hour period of 7.2 or observing and recording the capability of the backup's functionality while maintaining master control and operations at the primary facility. From a compliance audit consistency perspective this needs to be clarified either in the standard or in the measure for R7
Individual
Laura Zotter
ERCOT ISO
Yes
Adds clarity.
No
This change is an improvement however, the phrase 'situational awareness of the BES' is undefined, unmeasurable, and therefore open to interpretation. ERCOT ISO proposes changing 1.2.1 to read "Tools and applications that facilitate reliable operation of the BES" Also open to interpretation is ‘operating personnel’, which ERCOT ISO also thinks should be changed to ‘System Operator’.
Yes
Adds clarity, however ERCOT ISO thinks the phrase in the last sentence of R4 “To avoid requiring tertiary functionality,” could lead to confusion and therefore recommends striking this phrase. The remaining language speaks for itself and, we believe, the intent of the requirement.
No
To completely mitigate any potential confusion of the independence applied to the relationship between each entity’s primary and back-up control center and the independence between the facilities of different entities (different RCs, TOs and/or BAs), the requirement could read as follows: R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities. The primary and back-up facilities of an entity subject to this requirement shall be independent of each other with respect to the functionality required to maintain compliance with Reliability Standards. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]
Yes
No

Individual
Dan Rochester
Independent Electricity System Operator
Yes
Yes
Yes
Yes
No
(1) R6: We do not agree with determining VSLs according to the VRF levels. A VRF represents the level of reliability impact on the bulk electric system if the requirement is not met; whereas a VSL represents the extent to which a requirement is not met. The latter is independent of the former. (2) R7, Medium VSL: The condition before the “OR” is missing.
No
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
No
The following change is suggested: "...until such time that control can be transfered back to the primary control facility."
Yes
Yes
No
There is a question on whether operating personnel are excluded from "capability".
Individual
Martin Bauer
US Bureau of Reclamation
Yes
Yes
Yes
Yes
Yes
No
Group
Kansas City Power & Light
Michael Gammon
Yes

No
“Tools and applications” are the minimum means established by this standard to have BES awareness. If this implies Energy Management System functionality in whole or in part, then this requirement is too stringent for smaller entities where methods and procedures may be their back-up. Smaller entities that have few substations to monitor may send personnel to monitor those stations.
Yes
Yes
No
VSL for R8 has a “responsible entity” coordinating with a Regional Entity. My understanding of Regional Entity is that represents a compliance organization. Shouldn’t a Registered Entity coordinate and communicate with other operating entities such as their Regional Reliability Organization, Reliability Authority or Reliability Coordinator? And wouldn’t a Reliability Authority or Reliability Coordinator coordinate with other operating entities such as other TOP’s, BA’s, Reliability Authorities or Reliability Coordinators?
Yes
1. R1.1.2: Data communications should not be a minimum required element. Some entities are small enough, manning stations as a substitute for telemetered data would be sufficient. This requirement imposes equipment and costs for smaller entities that is neither needed or justifiable. 2. R1.2.5 is duplicative and redundant to the CIP-002 standard whichrequires an entity to evaluate all of their assets which would include the backup control center/functionality and is not needed here. 3. R4 is requiring an EMS computer system in whole or in part to fulfill the “logging and alarming” part of this requirement. This standard should continue to addressing itself to requiring the establishment of monitoring and controlling the BES through any combination of tools, methods and procedures appropriate to the Registered Entity at a back-up facility. Recommend the wording should be changed to “Each Balancing Authority and Transmission Operator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity’s control center staffed with certified Balancing Authority and Transmission Operator operators when control has been transferred to the backup facility) that provides the functionality required for fulfilling its functional obligations.” 4. R8 needs to be reworked to for Reliability Coordinators, Balancing Authorities, and Transmission Operators to coordinate with other operating entities and not the Regional Entity which is a compliance entity and not an operating entity.

Consideration of Comments on the 4th Draft of Standards for Back-up Facilities (Project 2006-04)

The Back-up Facilities Standard Drafting Team thanks all commenters who submitted comments on the 4th draft of EOP-008-1 — Loss of Control Center Functionality. The standard was posted for a 30-day public comment period from February 4-March 8, 2010. Stakeholders were asked to provide feedback through a special electronic comment form. The drafting team received 34 sets of comments, including comments from more than 90 different people from over 60 companies representing 8 of the 10 Industry Segments in the Registered Ballot Body as shown in the table on the following pages.

All comments have been posted in their original format at the following site:

http://www.nerc.com/filez/standards/Backup_Facilities.html

In this report the comments have been sorted so it is easier to see where there is consensus.

The SDT made only minor semantic changes based on this round of industry comments as summarized below and as a result is recommending that the Standards Committee advance this project back to the balloting stage.

The vast majority of comments received supported the changes made by the SDT and there are no significant minority points of view to report.

Requirements changed: R1, R1 — part 1.2: bullet #1, R5 — part 5.1, R6, and R8.

R1. — Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum:

R1, part 1.2 — Tools and applications to ensure that System Operators have situational awareness of the BES.

R5, part 5.1 — An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

R6 — Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

R8. — Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality.

Data retention changes: bullets 1 & 5.

1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the time period since its last compliance audit in accordance with Measurement M1.

5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.

VSLs changed: R5, R6, and R7 Severe.

Requirement	Lower	Moderate	High	Severe
R5	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that it's dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.
R7	The responsible entity conducted an annual test of its Operating Plan for backup functionality but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 0.5 continuous hours.

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 Vice President and 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.

Index to Questions, Comments, and Responses

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.	Individual	Tom Webb	Upper Peninsula Power Company and Wisconsin Public Service Corp			X	X	X					
2.	Group	Ben Li	ISO/RTO Standards Review Committee		X								
3.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
4.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	James Castle	NYISO	NPCC	2
3.	Matt Goldberg	ISONE	NPCC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Bill Phillips	MISO	RFC	2
6.	Lourdes Estrada-Salinero	CAISO	WECC	2
7.	Mark Thompson	AESO	WECC	2
8.	Charles Yeung	SPP	SPP	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Chuck Lawrence		American Transmission Company	MRO						1			
2.	Tom Webb		Wisconsin Public Service	MRO						3, 4, 5, 6			
3.	Terry Bilke		Midwest ISO Inc.	MRO						2			
4.	Jodi Jenson		Western Area Power Administration	MRO						1, 6			
5.	Ken Goldsmith		Alliant Energy	MRO						4			
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO						1, 3, 5, 6			
7.	Eric Ruskamp		Lincoln Electric System	MRO						1, 3, 5, 6			
8.	Joseph Knight		Great River Energy	MRO						1, 3, 5, 6			
9.	Joe DePoorter		Madison Gas & Electric	MRO						3, 4, 5, 6			
10.	Scott Nickels		Rochester Public Utilties Address	MRO						4			
11.	Terry Harbour		MidAmerican Energy Company	MRO						1, 3, 5, 6			
5.	Group	Guy V. Zito	NPCC Regional Standards Committee										X
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Kathleen Goodman		ISO New England	NPCC						2			
2.	Gregory Campoli		New York ISO	NPCC						2			
3.	Michael Lombardi		Northeast Utilities	NPCC						1			
4.	Brian Gooder		Ontario Power Generation	ERCOT						5			
5.	Donald Nelson		MA Dept. Public Service	NPCC						9			
6.	Alan Adamson		New York State Reliabilty Council	NPCC						10			
7.	Ben Eng		New York Power Authority	NPCC						3			
8.	Michael Garton		Dominion	NPCC						5			
9.	David Kiguel		Hydro One Networks	NPCC						1			
10.	Roger Champagne		TransEnergie HQ	NPCC						1			
6.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Jack Kerr			SERC						1			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
2. Louis Slade				RFC						5			
3. Mike Garton				NPCC						6			
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Jim Burns			BPA, Transmission Services, Technical Operations	WECC						1			
8.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Dave Folk			FE	RFC						1, 3, 4, 5, 6			
2. Doug Hohlbaugh			FE	RFC						1, 3, 4, 5, 6			
9.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		X								
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Kirit Shah			Ameren	SERC						1			
2. Joe Knight			Great River Energy	MRO						1, 3, 5, 6			
10.	Group	Jim Case	SERC OC Standards Review Group	X		X							
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Gerry Beckerle			Ameren	SERC						1, 3			
2. Andy Burch			Electric Energy, Inc.	SERC						1, 5			
3. Tim Hattaway			PowerSouth	SERC						1, 3, 5, 9			
4. Jack Kerr			Dominion Virginia Power	SERC						1, 3			
5. Robert Thomasson			Big Rivers Electric Cooperative	SERC						9, 1, 3, 5			
6. Stephen Mizelle			Southern Co. Transmission	SERC						1, 3, 5			
7. Alan Jones			Alcoa Power Gen Inc.	SERC						1, 5			
8. Chad Randall			E.ON.US	SERC						1, 3, 5			
9. Gloria Miller			E.ON.US	SERC						1, 3, 5			
10. Steve Fritz			ACES Power Marketing	SERC						6			
11. Sam Holemen			Duke	SERC						1, 3, 5			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
12.	Gary Hutson		SMEPA	SERC						1, 3, 5			
13.	Dave Pond		TVA	SERC						1, 3, 5, 9			
14.	Larry Akens		TVA	SERC						1, 3, 5, 9			
15.	Gene Delk		SCE&G	SERC						1, 3, 5			
16.	John Rembold		South Illinois Power Cooperative	SERC						1, 3, 5			
17.	Jim Busbin		Southern Co Transmission	SERC						1, 3, 5			
18.	Marc Butts		Southern Co Transmission	SERC						1, 3, 5			
19.	Ron Wyble		City of Columbia, MO - CWLD	SERC						1, 3, 5, 9			
20.	George Carruba		East kentucky Power Cooperative	SERC						1, 3, 5, 9			
21.	Mike Hardy		Southern Co. Transmission	SERC						1, 3, 5			
22.	Edd Forsythe		TVA	SERC						1, 3, 5, 9			
23.	Mike Bryson		PJM	RFC						2			
24.	John Neagle		AECI	SERC						1, 3, 5			
25.	John Johnson		SERC	SERC						10			
11.	Group	JT Wood	Southern Company Transmission	X		X		X	X				
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Mark Pratt		Southern Company Generation	SERC						5			
2.	Chris Wilson		Southern Company Transmission	SERC						1			
3.	Mike Sanders		Southern Company Transmission	SERC						1			
4.	Marc Butts		Southern Company Transmission	SERC						1			
5.	Pat Kohler		Southern Company Transmission	SERC						1			
6.	Jim Viikinsalo		Southern Company Transmission	SERC						1			
7.	Stephen Mizelle		Southern Company Transmission	SERC						1			
12.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Tom Saitta		KCPL	SPP						1, 3, 5, 6			
2.	Jim Useldinger		KCPL	SPP						1, 3, 5, 6			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
3.	Denney Fales		KCPL	SPP						1, 3, 5, 6			
13.	Individual	Michael R. Lombardi	Northeast Utilities	X									
14.	Individual	Lee Pedowicz	NPCC									X	
15.	Individual	Kelly Wolfe	Black Hills Power	X		X							
16.	Individual	Brenda Lyn Truhe	PPL Electric Utilities	X		X							
17.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
18.	Individual	Frank Cumpton	BGE	X									
19.	Individual	Luke Weber	We Energies			X	X	X					
20.	Individual	Joylyn Faust	Consumers Energy			X	X	X					
21.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
22.	Individual	Ralph F Meyer	The Empire District Electric Company	X		X							
23.	Individual	Edwin Thompson	Consolidated Edison Co. of New York	X		X		X	X				
24.	Individual	Michael Ayotte	ITC Holdings	X									
25.	Individual	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				
26.	Individual	Darryl Curtis	Oncor Electric Delivery LLC	X									
27.	Individual	Todd Lietz	Seattle City Light	X		X						X	
28.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Scott Barfield (behalf of Wayne Pourciau)	Georgia System Operations Corporation			X	X						
30.	Individual	Jason Shaver	American Transmission Company	X									
31.	Individual	Laura Zotter	ERCOT ISO		X								X
32.	Individual	Dan Rochester	Independent Electricity System Operator		X								
33.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
34.	Individual	Martin Bauer	US Bureau of Reclamation					X					

1. **Requirement R1, part 1.1: 'prolonged period of time' was replaced with 'the time it takes to restore the primary control center functionality'. Do you agree with this change? Please supply specific reasons for your comments.**

Summary Consideration: The overwhelming majority of commenters supported the SDT changes. However, there was one comment suggesting a semantic, clarifying change to Requirement R1 that the SDT thought would prove useful.

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum:

Organization	Yes or No	Question 1 Comment
Brazos Electric Power Cooperative, Inc.	No	The following change is suggested:"...until such time that control can be transfered back to the primary control facility."
Response: Your revision provides an interesting clarification. However, the SDT believes it may be too limiting in the cases of entities choosing to continue to use the backup functionality and not transferring back to the primary control center. This may be a likely scenario for entities that have 2 live control centers. No change made.		
ITC Holdings	No	The modification made to address the comments loses sight of the intent which is that you must be prepared for the loss of your primary control for varying lengths of time. Suggest the following language as an alternative: "The location and method of implementation for providing backup functionality during the period of the time that the primary control center functionality is unavailable."
Response: The SDT believes that the standard as written says the same thing your revision suggests, just using different words. Neither implies a specified length of time, only that the backup functionality is needed regardless of the time required. No change made.		
We Energies	Yes	R1 applies to "Each RC, BA, and TOP and requires each to ensure 'reliable operations of the BES'." No single entity can ensure the reliability of the BES. Rather these entities ensure the reliability of the BES working together fulfilling their functional obligations. We suggest "ensures reliable operations of the BES" be changed to "continues to meet their functional obligations."
Response: The SDT agrees that no single entity can ensure the reliability of the entire BES and has replaced that phrase with 'continues to meet their functional obligations with regard to the reliable operation of the BES…'. **R1**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it		

Organization	Yes or No	Question 1 Comment
continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum:		
American Transmission Company	Yes	
Black Hills Power	Yes	
Bonneville Power Administration	Yes	
Consolidated Edison Co. of New York	Yes	
Consumers Energy	Yes	
Electric Market Policy	Yes	
FirstEnergy	Yes	
Georgia System Operations Corporation	Yes	
Independent Electricity System Operator	Yes	
ISO/RTO Standards Review Committee	Yes	
Kansas City Power & Light	Yes	
Midwest ISO Standards Collaborators	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 1 Comment
NPCC	Yes	
NPCC Regional Standards Committee	Yes	
Oncor Electric Delivery LLC	Yes	
PacifiCorp	Yes	
Pepco Holdings, Inc.	Yes	
PPL Electric Utilities	Yes	
Seattle City Light	Yes	
SERC OC Standards Review Group	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission	Yes	
US Bureau of Reclamation	Yes	
Xcel Energy	Yes	
ERCOT ISO	Yes	Adds clarity.
BGE	Yes	BGE agrees with the proposed clarification of this statement.
Manitoba Hydro	Yes	The change makes it obvious that a backup plan is required for any failure of the primary control center. The previous statement “prolonged period” provided a loop hole meaning that not all primary control center failures require a backup plan, especially short duration ones.

Organization	Yes or No	Question 1 Comment
MRO's NERC Standards Review Subcommittee	Yes	The MRO supports the change the new verbiage provides clarity lacking in the previous revision.
The Empire District Electric Company	Yes	This provides more clarity.
Upper Peninsula Power Company and Wisconsin Public Service Corp	Yes	Wisconsin Public Service Corp (WPSC) supports the change the new verbiage provides clarity lacking in the previous revision.
Response: Thank you for your response.		

2. **Requirement R1, part 1.2.1: 'allow visualization capabilities' has been deleted thus placing the onus on situational awareness of the BES. Do you agree with this change? Please supply specific reasons for your comments.**

Summary Consideration: The overwhelming majority of commenters supported the SDT's position. However, there was one clarifying suggestion that the SDT thought provided value as shown below:

Requirement R1, part 1.2: bullet #1 - Tools and applications to ensure that System Operators have situational awareness of the BES.

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	No	"Tools and applications" are the minimum means established by this standard to have BES awareness. If this implies Energy Management System functionality in whole or in part, then this requirement is too stringent for smaller entities where methods and procedures may be their back-up. Smaller entities that have few substations to monitor may send personnel to monitor those stations.
Response: The concept of situational awareness has been widely used in the electric industry since 2005 where it was used in the blackout reports prepared by NERC and the U.S.-Canada Power System Outage Task Force. In the context of the blackout report, as in standard EOP-008, it means knowing what is going on in the system you control, and having sufficient information to understand what needs to be done to maintain or return to a reliable operating state. Therefore, for each entity, the specific methods and information that would be needed to maintain situational awareness may be different. No change made.		
Manitoba Hydro	No	Cannot find a historic reason why "visual capabilities" is being removed. Data and voice communications along with visual capabilities are all required for situational awareness of the BES. If SDT is considering making changes to 1.2 consider this example: 1.2. A summary description of the elements required to support the backup functionality and to provide operating personal situational awareness capabilities and operational control of the BES. These elements shall include, at a minimum: 1.2.1. Tools and applications that allow visualization capabilities. 1.2.2. Tool and applications for continuous Data updating and exchange. 1.2.3. Tools and applications to maintain viable Voice communications. 1.2.4. Power source(s). 1.2.5. Physical and cyber security. Data, voice and visual capabilities are three basic elements required for situational awareness for operating

Organization	Yes or No	Question 2 Comment
		personnel. Removing 'visual', while leaving the voice and data portion of situational awareness does not make sense.(Situational awareness: to detect and interpret information and events and integrate the impact of your own actions in a dynamic environment)
Consolidated Edison Co. of New York	No	It is unrealistic to assume that the RC, TOP, and BA will maintain "situational awareness" without "visualization capabilities". In fact, the 2003 Blackout Report, Recommendation 22 directly addressed this topic. It stated "A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities. In addition, the failure of FE's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO's incomplete tool set and the failure to supply its state estimator with correct system data on August 14 contributed to the lack of situational awareness. The need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations". It is not understood how an entity will demonstrate "situational awareness" without some type of visualization tool; whether their own, or another entities as stated in R3? The SDT should consider re-phrasing the sentence to read "Tools and applications with sufficient visualization capability to ensure situational awareness of the BES".
Response: The SDT agrees that visualization capabilities are needed to ensure that situational awareness exists. The industry comments to previous postings indicated that the industry did not understand what visualization capabilities were. Since visualization is a component of situational awareness, the SDT removed the visualization language from the standard, with the understanding that some tools, applications, and visualization will be necessary to demonstrate situational awareness. No change made.		
Consumers Energy	No	Neither statement is terribly efficient. Both leave ambiguity in the standard. Suggested verbiage would include: "Tools and applications to ensure similar functionality as available at the Primary Control Center."
Response: The SDT did not want to specify that displays and visualization tools used at the primary control center must be exactly duplicated at the backup control facility, but did want to use language that made it clear that operating personnel had to have sufficient information to remain aware of the state of the system, and have an understanding of what was needed to maintain or restore the system to a reliable operating state. The SDT believes that the long used and accepted concept of situational awareness explained that concept. No change made.		
Xcel Energy	No	Comments: what tools constitute adequate situational awareness? Is there a reference or another standard that would define this?
MRO's NERC Standards Review Subcommittee	No	The MRO agrees with the removal of the phrase "allows visualization of capabilities" but disagrees with the addition of the phrase "situational awareness of the BES." "Situational awareness of the BES" is neither a defined term nor is it a requirement for a primary control center. Using this term would result in the request for interpretations, inconsistent enforcement, or rule making through enforcement. To address this issue the

Organization	Yes or No	Question 2 Comment
		MRO suggest the verbiage of R1.2.1 be revised to state:"1.2.1. Tools and applications that ensures reliable operations of the BES."
Upper Peninsula Power Company and Wisconsin Public Service Corp	No	Wisconsin Public Service Corp agrees with the removal of the phrase “allows visualization of capabilities” but disagrees with the addition of the phrase “situational awareness of the BES.” “Situational awareness of the BES” is neither a defined term nor is it a requirement for a primary control center. Using this term would result in the request for interpretations, inconsistent enforcement, or rule making through enforcement. To address this issue the Wisconsin Public Service Corp suggest the verbiage of R1.1.2 be revised to state:"1.2.1. Tools and applications that ensures reliable operations of the BES."
Southern Company Transmission	Yes	More definition of the term “situational awareness” would be helpful
Response: While situational awareness is not a defined term, it has been widely used in the electric industry since 2005 where it was used in the blackout reports prepared by NERC and the U.S.-Canada Power System Outage Task Force. In the context of the blackout report, as in standards EOP-008 it means knowing what is going on in the system you control, and having sufficient information to understand what needs to be done to maintain or return to a reliable operating state. No change made.		
We Energies	No	The term “situational awareness” is subject to interpretation. Since R3 and R4 already specify backup control center capability “... that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a (Balancing Authority and Transmission Operator’s) primary control center functionality ...” it recommended that R1.2.1 be eliminated from the standard.
Response: Requirement R1, part 1.2 is intended to provide a minimum list of the elements needed to provide adequate backup functionality. One of those is the ability of operating personnel to have sufficient information to remain aware of the state of the system and to understand what needs to be done to maintain or return to a reliable operating state. This concept of situational awareness, while not a defined term, has been widely used in the electric industry since 2005 where it was used in the blackout reports prepared by NERC and the U.S.-Canada Power System Outage Task Force. The BFSDT believes that requirement 1.2.1 provides clarity to the elements that are expected to be provided. No change made.		
ERCOT ISO	No	This change is an improvement however; the phrase 'situational awareness of the BES' is undefined, unmeasurable, and therefore open to interpretation. ERCOT ISO proposes changing 1.2.1 to read "Tools and applications that facilitate reliable operation of the BES" Also open to interpretation is ‘operating personnel’, which ERCOT ISO also thinks should be changed to ‘System Operator’.
Response: While situational awareness is not a defined term, it has been widely used in the electric industry since 2005 where it was used in the blackout reports prepared by NERC and the U.S.-Canada Power System Outage Task Force. In the context of the blackout report, as in standard EOP-008 it means knowing what		

Organization	Yes or No	Question 2 Comment
is going on in the system you control, and having sufficient information to understand what needs to be done to maintain or return to a reliable operating state. No change made. System Operator – The SDT assumes you meant Part 1.2.1 and if so, agrees with your comment on replacing 'operating personnel' with 'System Operators'. **Requirement R1, part 1.2, bullet #1 -** Tools and applications to ensure that System Operators have situational awareness of the BES		
American Transmission Company	Yes	
Black Hills Power	Yes	
Bonneville Power Administration	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
Electric Market Policy	Yes	
FirstEnergy	Yes	
Georgia System Operations Corporation	Yes	
Independent Electricity System Operator	Yes	
ISO/RTO Standards Review Committee	Yes	
Midwest ISO Standards Collaborators	Yes	
Northeast Utilities	Yes	
NPCC	Yes	

Organization	Yes or No	Question 2 Comment
NPCC Regional Standards Committee	Yes	
Oncor Electric Delivery LLC	Yes	
PacifiCorp	Yes	
Pepco Holdings, Inc.	Yes	
PPL Electric Utilities	Yes	
Seattle City Light	Yes	
SERC OC Standards Review Group	Yes	
South Carolina Electric and Gas	Yes	
The Empire District Electric Company	Yes	
US Bureau of Reclamation	Yes	
BGE	Yes	BGE agrees this change is acceptable.
ITC Holdings	Yes	None
Response: Thank you for your response.		

3. Requirements R3 & R4: 'when control has been transferred to the backup…' was added to emphasize that operators are only required at the backup when it is in service. Do you agree with this change? Please supply specific reasons for your comments.

Summary Consideration: The overwhelming majority of industry comments agreed with the SDT's position and no changes have been made to the standard based on the comments received here.

Organization	Yes or No	Question 3 Comment
ERCOT ISO	Yes	Adds clarity; however ERCOT ISO thinks the phrase in the last sentence of R4 "To avoid requiring tertiary functionality," could lead to confusion and therefore recommends striking this phrase. The remaining language speaks for itself and, we believe, the intent of the requirement.
Response: The SDT felt that this phrasing "To avoid requiring tertiary functionality" was needed to add clarity to the requirement. This statement would eliminate possible confusion so that entities did not think that a third facility would be required during maintenance outages to the backup facility. No change made.		
MRO's NERC Standards Review Subcommittee	Yes	The MRO supports the clarification described in R4. We suggest removing the phrase "of two weeks or less." The length of allowable outage regardless if it is planned or unplanned has the same effect on the BES and should be treated consistently in R8.
Upper Peninsula Power Company and Wisconsin Public Service Corp	Yes	The Wisconsin Public Service Corp supports the clarification described in R4. We suggest removing the phrase "of two weeks or less." The length of allowable outage regardless if it is planned or unplanned has the same effect on the BES and should be treated consistently in R8.
Response: The SDT felt that a timeframe was essential with respect to planned outages to the backup functionality otherwise an entity could have its backup functionality out of service under a planned condition indefinitely. This would create a major gap within the standard. The two week timeframe was considered a reasonable timeframe for planned outages by the SDT. No change made.		
ISO/RTO Standards Review Committee	Yes	We agree with the changes but suggest rewording that part pertaining to compliance to reliability standards as follows: Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for fulfilling its functional obligations. To avoid requiring a tertiary facility, a backup facility is not required during: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]
Response: The SDT felt that using ''maintaining compliance with all Reliability Standards that depend on primary control center functionality' was more specific and identified the requirement to meet NERC standards and not just functional obligations. No change made.		

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	While we agree with the change to emphasize that operators are only required at the backup facility when it is in service, upon further reflection we question the need to specify that certified staff are required in requirements R3 and R4, respectively: "staffed with certified Reliability Coordinator operators" and "staffed by applicable certified operators". The requirement for staffing with certified operators is contained in PER-003 which makes no distinction between primary and backup control centers. Adding this certification language to this standard essentially duplicates the requirement in PER-003. In addition, the delegation of a task requires comparable certification for those performing that task and the NERC Standards Committee is working to document this in the NERC Rules of Procedure. Therefore, we believe these statements are redundant to PER-003 and suggest they be removed.
Response: The SDT believes that the requirement as written is necessary to make clear that contracted backup services need to be staffed with NERC certified operators. The proposed draft of PER-003 is suggesting that the cited requirement be deleted. Therefore, the SDT feels that the requirement is necessary here to ensure that qualified operators are available. No change made.		
American Transmission Company	Yes	
Black Hills Power	Yes	
Bonneville Power Administration	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
Consolidated Edison Co. of New York	Yes	
Consumers Energy	Yes	
Electric Market Policy	Yes	
Georgia System Operations Corporation	Yes	
Independent Electricity System	Yes	

Organization	Yes or No	Question 3 Comment
Operator		
Kansas City Power & Light	Yes	
Midwest ISO Standards Collaborators	Yes	
Northeast Utilities	Yes	
NPCC	Yes	
NPCC Regional Standards Committee	Yes	
Oncor Electric Delivery LLC	Yes	
PacifiCorp	Yes	
Pepco Holdings, Inc.	Yes	
PPL Electric Utilities	Yes	
Seattle City Light	Yes	
SERC OC Standards Review Group	Yes	
South Carolina Electric and Gas	Yes	
Southern Company Transmission	Yes	
The Empire District Electric Company	Yes	

Organization	Yes or No	Question 3 Comment
US Bureau of Reclamation	Yes	
We Energies	Yes	
Xcel Energy	Yes	
BGE	Yes	BGE agrees this change is a necessary clarification.
ITC Holdings	Yes	None
Manitoba Hydro	Yes	Sometimes stating the obvious removes all doubt. Without the addition of this statement, it could be perceived that when control is transferred to a backup facility, qualified staff would not be required. This also enhances M3 and M4 measures. This clarifies that qualified staff are required to operate the backup facility when it is in control.
Response: Thank you for your response.		

4. Requirement R6: 'can independently maintain' was replaced with 'do not depend on each other…' Do you agree with this change? Please supply specific reasons for your comments.

Summary Consideration: The majority of industry comments agreed with the SDT's changes. However, there were some suggestions for additional clarity that the SDT thought provided value as shown below.

Requirement R5, part 5.1 - An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality.

Organization	Yes or No	Question 4 Comment
Electric Market Policy	No	
Response: Without a specific comment, the SDT is unable to respond.		
Georgia System Operations Corporation	No	Instead of "primary and backup capabilities do not depend on each other" is would read better for consistency and clarity "primary and backup functionalities do not depend on each other". The same goes for R5.1 and R8 and the associated measures where the word "capabilities" was used.
Response: The SDT agrees that "capabilities" should be changed to "functionality" as you have requested. However, it must be understood that a Reliability Coordinator achieves this through a backup facility and the Balancing Authority and Transmission Operator can do so through a backup facility or contracted services. **R6.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. **Requirement R5, part 5.1** - An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1. **R8**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality.		

Organization	Yes or No	Question 4 Comment
Consolidated Edison Co. of New York	No	The language can be clarified by stating “.....shall have independent primary and backup capabilities and functionalities required to ....” The term “do not depend on each other” should be removed since its meaning is vague.
Response: The SDT believes that “do not depend on each other” is appropriate language to use here. There certainly are many ways to word this requirement, but the vast majority of commenters agreed with this language and the SDT will proceed with the majority’s opinion. No change made.		
MRO's NERC Standards Review Subcommittee	No	The phrase “do not depend on each other for” is no less ambiguous than “can independently maintain” therefore the MRO does not support this change. Furthermore, the required level of redundancy and separation can not be adequately defined until the scope (radius) of damage to the primary control center is defined and if other single failure (n-1) scenarios must be considered. The MRO suggests that the N-1 scenario includes, and should be limited to, the primary control center and its energy management system. Other systems, communication systems and communication rooms outside of the rooms that house primary control center or primary energy management system would be assumed to be intact and fully operable. Failure to first define the level of assumed damage will result in the request for interpretations, inconsistent enforcement, and rule making through enforcement.
Upper Peninsula Power Company and Wisconsin Public Service Corp	No	The phrase “do not depend on each other for” is no less ambiguous than “can independently maintain” therefore Wisconsin Public Service Corp does not support this change. Furthermore the required level of redundancy and separation can not be adequately defined until the scope (radius) of damage to the primary control center is defined and if other single failure (n-1) scenarios must be considered. Wisconsin Public Service Corp suggests that the N-1 scenario include, and be limited to, the primary control center and its energy management system. Other systems, communication systems and communication rooms outside of the rooms that house primary control center or primary energy management system would be assumed to be intact and fully operable. Failure to first define the level of assumed damage will result in the request for interpretations, inconsistent enforcement, and rule making through enforcement.
Response: The SDT believes that “do not depend on each other” is appropriate language to use here. There certainly are many ways to word this requirement, but the vast majority of commenters agreed with this language and the SDT will proceed with the majority’s opinion. No change made. Regarding the N-1 scenario, the SDT is citing requirements for what to do to maintain the functionality required to achieve compliance with Reliability Standards with your backup functionality. The SDT is not stating how an entity accomplishes this. No change made.		
Black Hills Power	No	The phrase “primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards” is unclear and implies a requirement of redundant facilities well outside of the control center. For example, a loss of “capability” may be considered to have occurred a)

Organization	Yes or No	Question 4 Comment
		in the event of a loss of SCADA communications caused by equipment failures outside of the control center or b) loss of RTU functionality within a substation. In this case, a “primary capability” (i.e. EMS tie line monitoring obtained from a failed substation RTU or a failed communications circuit) depends on a “backup capability” (the same RTU and/or communications circuit) which are both removed from the control center. As written, the Standard seems to require redundant communications and RTUs since a “loss of capability” would exist in these cases. I suspect that the Standard is actually intended to only provide redundancy of equipment located at the control center facility but, as written, seems to actually require redundancy of equipment far away from the control center. This is too broad of a scope for the implied intent of this Standard and should be re-written
Response: The SDT believes that “do not depend on each other” is appropriate language to use here. There certainly are many ways to word this requirement, but the vast majority of commenters agreed with this language and the SDT will proceed with the majority’s opinion. No change made. The SDT is citing requirements for what to do to maintain the functionality required to achieve compliance with Reliability Standards with your backup functionality. The SDT is not stating how an entity accomplishes this. No change made.		
Brazos Electric Power Cooperative, Inc.	No	There is a question on whether operating personnel are excluded from "capability".
Response: Personnel are excluded until control is transferred to the facility, which was clarified by the wording added to Requirements R3 and R4 in the fourth posting. No change made.		
ERCOT ISO	No	To completely mitigate any potential confusion of the independence applied to the relationship between each entity’s primary and back-up control center and the independence between the facilities of different entities (different RCs, TOs and/or BAs), the requirement could read as follows: R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall haveprimary and backup capabilities. The primary and back-up facilities of an entity subject to this requirement shall be independent of each other with respect to the functionality required to maintain compliance with Reliability Standards. [ViolationRisk Factor = Medium] [Time Horizon = Operations Planning]
We Energies	Yes	Suggest adding the words "applicable to the Functional Entity" at the end: “Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards applicable to the Functional Entity.”
Response: The SDT does not feel that the suggested wording change provides any additional clarity. No change made.		

Organization	Yes or No	Question 4 Comment
Midwest ISO Standards Collaborators	No	We do not see the need for this change but can accept it if it will help others to support the standard.
Response: The change was implemented by the SDT due to comments from others in the industry, and we appreciate your flexibility.		
SERC OC Standards Review Group	No	We suggest adding the three (3) phrases (in quotes) in the sentence for additional clarification: Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup “control center” capabilities that do not depend on each other “or any common capability” for the functionality required, “as mentioned in R1, section 1.2”, to maintain compliance with Reliability Standards.
South Carolina Electric and Gas	No	We suggest adding the three (3) phrases (in quotes) in the sentence for additional clarification: Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup “control center” capabilities that do not depend on each other “or any common capability” for the functionality required, “as mentioned in R1, section 1.2”, to maintain compliance with Reliability Standards
Response: The SDT has made the requested change to the requirement. **R6.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards.		
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Independent Electricity System Operator	Yes	
ISO/RTO Standards Review Committee	Yes	
Kansas City Power & Light	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 4 Comment
NPCC	Yes	
NPCC Regional Standards Committee	Yes	
Oncor Electric Delivery LLC	Yes	
PacifiCorp	Yes	
Pepco Holdings, Inc.	Yes	
PPL Electric Utilities	Yes	
Seattle City Light	Yes	
Southern Company Transmission	Yes	
The Empire District Electric Company	Yes	
US Bureau of Reclamation	Yes	
Xcel Energy	Yes	
BGE	Yes	BGE agrees with the proposed clarification.
FirstEnergy	Yes	FE supports this change and thanks the SDT for incorporating our suggested change.
ITC Holdings	Yes	None
Manitoba Hydro	Yes	This does improve the statement and Measure R6 to more clearly indicate that the backup facility cannot be dependent on the primary facility.
Response: Thank you for your response.		

5. The SDT has made changes to the VSLs for this project based on the latest VSL guidelines. Do you agree with these changes? If not, please provide specific reasons for your comment.

Summary Consideration: The majority of the comments received agree with the SDT's position. However, some commenters suggested some clarifying changes for which the SDT saw merit as shown below:

R5 VSL	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that it's dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6 VSL	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.

R7 severe VSL - The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, the responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 0.5 continuous hours.

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator	No	(1) R6: We do not agree with determining VSLs according to the VRF levels. A VRF represents the level of reliability impact on the bulk electric system if the requirement is not met; whereas a VSL represents the extent to which a requirement is not met. The latter is independent of the former. (2) R7, Medium VSL: The condition before the "OR" is missing.
ISO/RTO Standards Review Committee	No	AESO would note that it does not comment on VSLs as VSLs are a Canandian Provincial matter (1) R6: We do not agree with determining VSLs according to the VRF levels. A VRF represents the level of reliability impact on the bulk electric system if the requirement is not met; whereas a VSL represents the extent to which a requirement is not met. The latter is independent of the former. (2) R7, Medium VSL: The condition before the "OR" is missing.
Response: 1. The SDT agrees that there is no correlation between VRF and VSL for an individual requirement. That is not what is happening here. The VSL for Requirement R6 is not referring to the VRF for Requirement R6. It is referring to all applicable requirements for a responsible entity that have a Lower VRF assigned to them in the respective standards. No change made. 2. There is no 'Medium' VSL category. The SDT believes you may have been referring to the 'Moderate' category. If so, it appears that you are looking at the redline copy which does contain an inadvertent 'OR'. This was fixed in the clean copy and the 'OR' is no longer there.		
Manitoba Hydro	No	Changes to R1 are fine Changes to R2 new VSL definitions are clearer. Could argue that the two VSL's be Lower and Moderate instead of Moderate and Severe but have no justification for this at this time. Change to R3 coincides with revision to Requirement R3 - fine. Change to R4 coincides with revision to Requirement R4 - fine. Changes to R5 are fine. R6 - Not sure why entities would have different VRF for the same requirement and therefore placed in different VSLs? R7- VSL as written focus too much on time lines, not whether the run was successful, or documented or done annually. VSL Lower - Did not document results of annual test, transition period or successful run greater than 2 hours.

Organization	Yes or No	Question 5 Comment
		VSL Moderate - Documented all, ran successful, but did not exceed 2 hours. VSL High - Documented all, ran successfully but test not done annually. VSL Severe -Combination of any two of the other two VSL's R8 - Instead of time line windows of reporting for each VSL, create specific failures. VSL Lower - Failed to identify loss will be greater than 6 months VSL Moderate - Failed to provide a plan when loss expected to exceed 6 months. VSL High - Failed to provide a plan within 6 months of failure. VSL Severe -
Response: R1 through R5 – Thank you for your comment. R6 – The VSL for Requirement R6 is not referring to the VRF for Requirement R6. It is referring to all applicable requirements for a responsible entity that have a Lower VRF assigned to them in the respective standards. No change made. R7 – The SDT feels that it would be difficult to determine whether a test was "successful", and that one purpose of a test is to identify shortcomings. Also, Requirement R7 does not include language about the "success" of the test so it would be inappropriate to include such criteria in the VSL. The SDT believes the duration of the test is important because it addresses the ability of the entity to operate using backup functionality for extended periods of time. No change made. R8 – It is difficult to see how a VSL of Lower could occur under the suggested language. An estimated schedule for restoring capability would be a fundamental element of a plan to re-establish backup functionality submitted to the Regional Entity. Accordingly, the SDT believes that a document submitted to the Regional Entity regarding re-establishment of backup capability but without an estimated time line for doing so would not be considered a plan meeting this requirement and would be a severe violation. With the suggested language, the Moderate language seems to be more severe than the High language because the Moderate language states that a plan was never supplied while the High language indicates only that it was provided late. This does not meet the intent of the SDT. No change made.		
MRO's NERC Standards Review Subcommittee	No	R1, R2, and R8 are documentation issues not a functionality issue. Therefore the maximum severity should be no more than moderate. With regards to R5, this is a documentation issue related to the control centers. It is not a functionality issue. Therefore it is hard to conceive of a documentation issue that could have a significant adverse affect on the reliability of the BES. Furthermore the materiality of the omitted updated material must be included in any discussion of risk factors. For example, failure to include and updated phone number in the plan documented has little or no affect on the reliability and safety of the BES. Whereas, outdated instructions on how to establish data communication would have more significance. Furthermore it is hard to conceive of a scenario of how an annual review, regardless of the definition of annual, overdue by one day could significantly affect the reliability of the BES especially if that annual review did not identify any changes. As R5 deals with

Organization	Yes or No	Question 5 Comment
		documentation and not functionality, violations of R5 should be low. With regards to R7, the failure to test or surveil a function should only be considered a high or severe issue if the lack of surveillance failed to assure or could have failed to assure an adequate response to a real event.
Upper Peninsula Power Company and Wisconsin Public Service Corp	No	R1, R2, and R8 are documentation issues not a functionality issue. Therefore the maximum severity should be no more than low. With regards to R5, this is a documentation issue related to the control centers. It is not a functionality issue. Therefore it is hard to conceive of a documentation issue that could have a significant adverse affect on the reliability of the BES. Furthermore the materiality of the omitted updated material must be included in any discussion of risk factors. For example, failure to include and updated phone number in the plan documented has little or no affect on the reliability and safety of the BES. Whereas, outdated instructions on how to establish data communication would have more significance. Furthermore it is hard to conceive of a scenario of how an annual review, regardless of the definition of annual, overdue by one day could significantly affect the reliability of the BES especially if that annual review did not identify any changes. As R5 deals with documentation and not functionality, violations of R5 should be low. With regards to R7, the failure to test or surveil a function should only be considered a high or severe issue if the lack of surveillance failed to assure or could have failed to assure an adequate response to a real event.
Response: VSLs are not based on the risk to the BES; that concept is covered by the VRF. VSLs address the extent of the violation, i.e., did an entity fail to address the requirement at all, or did they address the spirit of the requirement but miss only a specific detail. Note that two of the requirements you note do have Lower VRFs and the others are Medium. For example, Requirements R1 and R8 have medium VRFs because the risk is not that the entity will not have documentation of the plans, but that they will not do the planning. Failure to plan for the loss of control center functionality could have an adverse effect on the reliability of the BES. No change made		
Bonneville Power Administration	No	Suggest reordering the sentences in VSL-R4 to put what they “did not” do prior to the phrase “when control has been transferred to the backup functionality location ...”. There appears to be no difference between Lower, Moderate and Severe except the reference to VRF. But the R4 standard Risk Factor is Medium risk. It appears to be trying to refer to Standards other than EOP-008 for functionality issues, but there is no list ... just ANY standards as applicable. R7 - Suggested Revisions: Lower = Test did not asses the transition and implementation times... remove the “OR”; Moderate = no documentation or test less than 2 hours...;

Organization	Yes or No	Question 5 Comment
		High = Test was less than 1 hour; Severe = NO annual test or less than 0.5 hrs.
Response: R4 – The SDT believes that if the suggested change was made the VSL would no longer match the wording or intent of the requirement. No change made. VRF – The SDT agrees that there is no correlation between VRF and VSL for an individual requirement. That is not what is happening here. The VSL for Requirement R4 is not referring to the VRF for Requirement R4. It is referring to all applicable requirements for a responsible entity that have a Lower VRF assigned to them in the respective standards. No change made. R7 – The SDT believes that the original VSLs correctly reflect the importance of each potential violation. No change made.		
We Energies	No	The VSLs for R1 should state clearly whether R1.2 is considered one requirement or several requirements. The VSLs for R6 should not be more severe than the VRFs for the applicable Reliability Standards. These VSLs are also tricky to read because they employ double negatives. Recommend wording such as “The responsible entity has primary and backup capabilities that depend on each other for the functionality required to maintain compliance with Reliability Standards applicable to the entity that have a Lower VRF.”
Response: R1 – Requirement R1, part 1.2 is not a requirement but a part of Requirement R1. The sub-parts shown under part 1.2 are to be considered as a whole, i.e., missing one of them would indicate that an entity has missed all of part 1.2. No change made. R6 – VRFs and VSLs are not directly comparable. Since there are only three levels of VRFs the SDT believes that it is appropriate to link them to the three most severe classifications of VSLs. Double negatives – The SDT agrees and has made the suggested changes.		

R6 VSL	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.

Organization	Yes or No	Question 5 Comment
Kansas City Power & Light	No	VSL for R8 has a "responsible entity" coordinating with a Regional Entity. My understanding of Regional Entity is that represents a compliance organization. Shouldn't a Registered Entity coordinate and communicate with other operating entities such as their Regional Reliability Organization, Reliability Authority or Reliability Coordinator? And wouldn't a Reliability Authority or Reliability Coordinator coordinate with other operating entities such as other TOP's, BA's, Reliability Authorities or Reliability Coordinators?
Response: The compliance entity is the right entity in this regard. Coordination is not the issue. Planning to recover from a catastrophe is the issue. No change made.		
SERC OC Standards Review Group	No	We suggest changing the VSLs for R5 to have a range of 30 calendar days in each of the Low, Moderate and High columns as opposed to 10 calendar days. These plans are reviewed annually and this time frame seems to line up better. Also, the VSLs for R5 do not parallel Section 5.1 of R5. The key part of Section 5.1 is "An update and approval of the Operating Plan". The VSLs currently do not contemplate reapproving the plan. An alternative solution would be to separate Section 5.1 into a unique requirement for "update" and 5.2 unique requirement for "approval". We also suggest making conforming changes to the VSLs for requirement 6 as noted in Question 4.
Response: R5 – The SDT has assigned the intervals based on established guidelines so that the intervals are more in line with the general timeframe involved. Changing the intervals to 30 days would create a 50% buffer which is considered too large. No change made. Section 5.1 – It is the SDT's position that the update of the Operating Plan is not complete until it has been approved. The SDT has changed the text of the VSL to clarify this point.		

R5 VSL	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that it's dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90

Organization	Yes or No	Question 5 Comment		
				calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6 - The SDT did not believe the additional language suggested in question 4 added any clarity to the requirement and no change was made in question 4 so no change is required here.				
South Carolina Electric and Gas	No	We suggest changing the VSLs for R5 to have a range of 30 calendar days in each of the Low, Moderate and High columns as opposed to 10 calendar days. These plans are reviewed annually and this time frame seems to line up better. Also, the VSLs for R5 do not parallel Section 5.1 of R5. The key part of Section 5.1 is "An update and approval of the Operating Plan". The VSLs currently do not contemplate reapproving the plan. An alternative solution would be to separate Section 5.1 into a unique requirement for "update" and 5.2 unique requirement for "approval". We also suggest making conforming changes to the VSLs for requirement 6 as noted in Question 4. For clarification in requirement 1 the VSL talks about "requirement's Parts." Is this the same thing as subrequirements? If not, is Parts a defined term (hence the capitalization)?		
Response: R5 – The SDT has assigned the intervals based on established guidelines so that the intervals are more in line with the general timeframe involved. Changing the intervals to 30 days would create a 50% buffer which is considered too large. No change made. Section 5.1 – It is the SDT's position that the update of the Operating Plan is not complete until it has been approved. The SDT has changed the text of the VSL to clarify this point.				
R5 VSL	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that it's dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup

Organization	Yes or No	Question 5 Comment

				functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.

R6 - The SDT did not believe the additional language suggested in question 4 added any clarity to the requirement and no change was made in question 4 so no change is required here.

Parts – Moving forward, there will no longer be sub-requirements in the standards. This was part of the ERO filing on the 'roll-up' of requirements and VRFs. Parts are capitalized as a grammatical construct and are not a defined term. No change made.

Organization	Yes or No	Question 5 Comment
Southern Company Transmission	Yes	Recommend wording change for VSL R6 to read "The responsible entity has primary and backup capabilities that depend on each other for the functionality required to maintain..." There seems to be a discrepancy between R6 which has a VRF of Medium and the VSL Table references which has lower and high as well as medium. R7 Moderate VSL appears to be missing a critical paragraph before the "OR". R7 Severe appears to be missing a "than" before "0.5 continuous hours".

Response: 1. The SDT has revised the VSLs for Requirement R6 based on your suggestion.

R6 VSL	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.

2. There is no correlation between the VRF assigned to a requirement and the VSL. VRF is an indication of the seriousness of not adhering to the requirement and the effect that would have on the bulk power system. VSL is an after-the-fact measure of how badly an entity missed the mark. No change made.

3. The "OR" should not have been included. Only one criterion was intended for the Moderate level.

Organization	Yes or No	Question 5 Comment
4. The SDT agrees and has made the change. **R7 severe VSL** - The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 0.5 continuous hours.		
Consolidated Edison Co. of New York	Yes	
Consumers Energy	Yes	
Electric Market Policy	Yes	
ERCOT ISO	Yes	
FirstEnergy	Yes	
Northeast Utilities	Yes	
NPCC	Yes	
NPCC Regional Standards Committee	Yes	
Oncor Electric Delivery LLC	Yes	
PacifiCorp	Yes	
Pepco Holdings, Inc.	Yes	
PPL Electric Utilities	Yes	
Seattle City Light	Yes	
The Empire District Electric Company	Yes	

Organization	Yes or No	Question 5 Comment
US Bureau of Reclamation	Yes	
BGE	Yes	BGE agrees with the changes to the VSLs.
Response: Thank you for your response.		

6. Do the proposed revisions to the standard pose any new issues or questions that haven't been raised and previously addressed? Please provide specific reasons for your comment.

Summary Consideration: One commenter requested a semantic change for additional clarity above and beyond the ones suggested in the previous questions which is shown below.

Data Retention bullet #1 – Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality for the time period since its last compliance audit in accordance with Measurement M1.

Data Retention bullet #5 - Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Measurement M5.

In addition, the following changes were noted in earlier questions and repeated here.

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum:

Requirement R1, part 1.2, bullet #1 - Tools and applications to ensure that System Operators have situational awareness of the

Requirement R5, part 5.1 - An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that does not depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality.

Organization	Yes or No	Question 6 Comment
BGE	No	It appears to be inconsistent that R4 requires obtaining a tertiary facility for planned outages lasting over 2 weeks, but that for forced outages of a primary or back up control center the only requirement, per R8, is to provide a plan within 6 months showing how the entity will re-establish backup capability but with no time-frame requirements.
Response: The SDT does not see any inconsistency between Requirement R4 and Requirement R8. Planned outages indicate a degree of control where you can determine the length of the outage and plan accordingly. The 2 week time period is a reasonable limit for most situations that the SDT could come up with.		

Organization	Yes or No	Question 6 Comment
With an unplanned outage, you have no (or little) control over the initiation or length of the outage. The SDT felt that it would be unreasonable to place a hard and fast time limit on unplanned outages as any time limit could eventually lead to requiring a tertiary system. Therefore, no time limit was placed in Requirement R4 and a six month time limit for a plan was established in Requirement R8. No change made.		
ITC Holdings	No	Suggest the following re-wording of Requirement 6 for clarity and alignment with R4:"Each RC, BA and TOP shall have primary and backup functionality, as identified in R3 and R4, which are not dependent on each other." In Requirement 8, suggest the following re-wording to align with R3 and R4: replace the word "capability" with "functionality".
Response: The SDT agrees that "capabilities" should be changed to "functionality" as you have requested. However, the addition of requirements R3 & r4 is seen as redundant verbiage that does not provide any additional clarity and that change has not been made. **R6.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. **R8**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality.		
ISO/RTO Standards Review Committee	Yes	(1) R1: Entities cannot "ensure" reliable operations of the BES. They can operate the BES within their footprint to contribute to interconnected system reliability in accordance with their responsible functionalities. We suggest "ensures reliable operations of the BES" be changed to" "continues to meet their functional obligations". (2) We think that this requirement puts the BA at a difficult and even non-compliant situation since the BA as a functional entity is not required to have access to the transmission conditions on the BES. Similarly, the TOP may not have access to any generation-load-interchange balance information. Further, we suggest to replace "operating personnel" with "System Operator" - a defined term for operators at the RC, BA and TOP control centres to which this EOP standard applies. The proposed wording of 1.2.2 would thus read: Tools and applications that to ensure that the RC, BA and TOP have the capability to meet their respective functional obligations. (3) R1.2.5: This is not required since CIP-002-2 R1 already requires a Critical Asset Identification Method which includes in R1.2.1, the Control centers and backup control centers performing the functions of the entities listed in the Applicability section of that standard. (4) R1.2 seems to be a requirement to only have a descriptive list, i.e. - a document. If the measure of

Organization	Yes or No	Question 6 Comment
		compliance to R1.2 is the presence of a document, then the subsequent sub requirements, 1.2.1, 1.2.2, 1.2.3, 1.2.4 1.2.5 should be reorganized as a list and not distinct sub requirements since these are not individually measured for compliance to R1.2. (5) R1.6.2 requires during the 2 hour period for transition to the backup center, the Operating Process must include "Actions to manage the risk to the BES...". It is unclear what "risk to the BES" must have actionable operations. If they include VSLs, IROLs and RSG requirements, all requiring action under the 2 hour period, then this may require a redundant parallel operation during the transition period since a neighboring BA, TOP, or RC may not have control to take "Action". We do not believe that is the intent, however, it is unclear what capabilities are required to be compliant to R1.6.2 during the 2 hour transition to the backup facility. (6) R5 and R7: The word annually leaves room for interpretation. Where annual reviews or testing are required, annually can mean "an event that occurs yearly" which can results in two events occurring within a month of the New Year. To add clarity to meeting the intent of having reviews/testing done periodically within a 12 month time frame, we recommend that the drafting team replace annual test/review requirements with "test/review once each calendar year but in no event can the duration between test/review exceed 18 months". This would allow entities to have flexibility within a calendar year to push back review/testing by 1-2 Quarters to address, for example, other business needs, but would not allow delays that result in reviews/testing more than 18 months apart. (7) R6: The way this requirement is worded can be ambiguous. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other for the functionality required to maintain..."The word capability may mean the capability of the responsibility or the capability of the functionality, and hence the "each other" could be interpreted as the responsible entity or the capability functionality. If this is meant to be the functionality, we suggest R6 be revised to provide clarity, such as: Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup capabilities that do not depend on each other to maintain... (8) R8: We suggest to replace the phrase "functionality is lost" with the loss of functionality is discovered" since the loss of functionality may not be known until it is checked periodically.

Response: 1. The SDT agrees that no single entity can ensure the reliability of the entire BES and has replaced that phrase with 'continues to meet their functional obligations with regard to the reliable operation of the BES…'.

> **R1**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum:

2. With the change made to Requirement R1 in response to your comment #1, any perceived problem with compliance should have been resolved. No change

Organization	Yes or No	Question 6 Comment
made. System Operator – The SDT assumes you meant Part 1.2.1 and if so, agrees with your comment on replacing 'operating personnel' with 'System Operators'. **Requirement R1, part 1.2, bullet #1 -** Tools and applications to ensure that System Operators have situational awareness of the BES 1.2.2. – Again the SDT assumes that you meant Part 1.2.1. The SDT believes that with the change made at your suggestion to Requirement R1 there is no reason to change the terminology here. No change made. 3. The SDT believes that physical and cyber security are essential elements of the backup plan. The backup plan must contain how the backup functionality handles physical and cyber security. If an entity has documentation from the CIP standards that covers these issues, they should just reference it in the backup plan. No change made. 4. The sub-parts under Part 1.2 are items that must be included in the plan and therefore should be numbered. No change made. 5. The SDT believes that a portion of the BES can not be left without oversight during the transition period. Responsible entities should plan to contact their neighbors to provide oversight to the extent possible during the transition. No change made. 6. The SDT disagrees with the change suggested. 'Annual' is used throughout the Reliability Standards and is well understood. No change made. 7. The SDT agrees that "capabilities" should be changed to "functionality" as you have requested. **R6.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. 8. The SDT does not agree with the suggested change as it could significantly alter the amount of time before the plan is required. No change made.		
MRO's NERC Standards Review Subcommittee	Yes	1. What is the significance of the two hours in R1.5? 2. Is it the intention to find the entity in violation if they can't get their back-up site fully functional within two hours for any reason? 3. We are concerned that the term "backup capabilities" has not been clearly defined or explained in the Standard. It is used in R6 and in R8. We feel that R6 should be changed to read: "Each RC, BA and TOP shall have primary and backup functionality, as defined in R4, that do not depend on each other." We recommend that R8 should replace the word capability with functionality.
Response: 1. In the judgment of the SDT, and as vetted through the various comment periods, two hours was selected as a reasonable time for establishing backup functionality. Two hours is the time between the loss of the primary functionality and full operation of the backup functionality. 2. The 2 hours cited is a design criterion. Each situation is normally reviewed by the Regional Entity in light of the circumstances involved. 3. The SDT agrees that "capabilities" should be changed to "functionality" as you have requested.		

Organization	Yes or No	Question 6 Comment
R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. **R8**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality.		
Kansas City Power & Light	Yes	1. R1.1.2: Data communications should not be a minimum required element. Some entities are small enough, manning stations as a substitute for telemetered data would be sufficient. This requirement imposes equipment and costs for smaller entities that is neither needed or justifiable. 2. R1.2.5 is duplicative and redundant to the CIP-002 standard which requires an entity to evaluate all of their assets which would include the backup control center/functionality and is not needed here. 3. R4 is requiring an EMS computer system in whole or in part to fulfill the “logging and alarming” part of this requirement. This standard should continue to addressing itself to requiring the establishment of monitoring and controlling the BES through any combination of tools, methods and procedures appropriate to the Registered Entity at a back-up facility. Recommend the wording should be changed to “Each Balancing Authority and Transmission Operator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity’s control center staffed with certified Balancing Authority and Transmission Operator operators when control has been transferred to the backup facility) that provides the functionality required for fulfilling its functional obligations.” 4. R8 needs to be reworked to for Reliability Coordinators, Balancing Authorities, and Transmission Operators to coordinate with other operating entities and not the Regional Entity which is a compliance entity and not an operating entity.
Response: 1. The SDT assumes that you meant Part 1.2.2. The requirement does not mandate how an entity provides the data communications. It simply asks an entity to explain how it will do the task. This would not preclude manning substations as long as it can be done within the timing requirements. No change made. 2. The SDT believes that physical and cyber security are essential elements of the backup plan. The backup plan must contain how the backup functionality handles physical and cyber security. If an entity has documentation from the CIP standards that covers these issues, it should just reference it in the backup plan. No change made. 3. Requirement R4 does not mandate an EMS. If an entity can supply the indicated functionality by other means, the wording of the requirement would allow that. No change made. 4. The compliance entity is the right entity in this regard. Coordination is not the issue. Planning to recover from a catastrophe is the issue. No change made.		

Organization	Yes or No	Question 6 Comment
Seattle City Light	Yes	1. The term annual is used in requirement R5 and R7. This term need to be defined as there are many interpretations of this as it is defined in commom dictionaries. Does this mean every calendar year, every 365 days, 12 months, or 13 months (as supposedly used by WECC for CIP)? Entities should not have to rely on their definition matching that of an auditor. I would suggest a defintion of "every calendar year not to exceed 15 months between occurances". 2. Requirement R1.3 discusses the process for maintaining functionality of backup facilities as being consistent with the primary facility. Does this imply they must have the exact same functionality? Or sufficient functionality for reliable BES operation?
Response: 1. The SDT disagrees with the change suggested. 'Annual' is used throughout the Reliability Standards and is well understood. No change made. 2. The requirement does not say 'exact'. An entity must have the functionality necessary to maintain compliance with all applicable Reliability Standards. No change made.		
American Transmission Company	Yes	ATC has raised the following concerns during previous commenting periods but they have not been adequately addressed by the drafting team. We believe that our concerns identify a major gap within the standard which must be addressed prior to balloting. ATC believes that the drafting team needs to drop the term "backup capabilities" used in requirements 6 and 8. Background information: Requirement 1.2 states that entities must have a summary description of the elements required to support the "backup functionality". Requirements 1.2.1 through 1.2.5 identify the specific elements required to support "backup functionality". Requirement 4 requires entities to "have "backup functionality" ... that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a BA's and TOP's primary control center functionality respectively." Requirement 6: Requirement 6 introduces a new term "backup capabilities" which we believe is attempting to reference Requirement 4 (R4) but could also be used by an auditor to expand the functionality requirements identified in R4. The drafting team should replace the term "backup capabilities" with the term "backup functionality" in order to strengthen this requirement's ties to Requirement 4. Suggested Modification: Each RC, BA and TOP shall have primary and backup functionality, as identified in R4, which are not dependent on each other. We believe that our suggested modification achieves the goal of the requirement but also limits the ability of an auditor to expand the requirement. If the drafting team disagrees with our modification then we believe that

Organization	Yes or No	Question 6 Comment
		they must specify which capabilities do not have to be dependent. Requirement 8:Similar to our concerns with proposed requirement 6 the drafting team uses the term "capabilities" but does not specify what it means. Suggested Modification: Each RC, BA and TOP that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more then six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality. We believe that our suggestion ties back appropriately to requirements 1.2 and 4, which identify what functionality has to be lost in order to trigger this requirement.
Response: The SDT agrees that "capabilities" should be changed to "functionality" as you have requested. **R6.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. **R8**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality.		
Black Hills Power	Yes	Comments applicable to the overall Standard: The phrase "loss of control center functionality" is a fundamental and critical term which determines compliance to this Standard. However, there is no description or definition of how auditors or Functional Entities would determine if "loss of control center functionality" occurred. For example, would a "loss of control center functionality" occur if one or many non-redundant SCADA communications lines to critical substation(s) became non-functional? In order to prevent future compliance enforcement issues, we request specific clarity on these terms within the Standard itself or the Glossary of Terms. Comment specific to R2:R2 states . . . "shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality." The term "shall have a copy" may imply a physical hard copy. We request modifying the language in the Standard to allow electronic access to the same Operating Plan. One proposal would be to change "shall have a copy of" to "shall have access to". Comment specific to R5 part 5.1:R5 reads "An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities described in Requirement R1. The phase "any changes in capabilities described in Requirement R1" is extremely broad and would seem to cause non-compliance for minor, insignificant changes such as SCADA system applications or version changes. We offer the following alternative phrase to prevent such issues- "any

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>changes in capabilities which would impact the Operating Plan described in Requirement R1”.

Comment specific to R8:Requirement R8 refer to a “loss of primary or backup capability” but there is no definition or description of what constitutes a loss of “capability” such as a single communication outage or perhaps a partial loss of capability due to an EMS software glitch that would exist at both primary and backup facilities. We request that the Standard clarify how the Functional Entity would determine or define a loss of “capability”.</td></tr>
<tr><td colspan="3">Response: 1. The standard states that an entity must be in a position to maintain compliance with all applicable Reliability Standards. Failure to maintain this compliance should be the indicator of when action must be taken. Additionally, Requirement R1, part 1.6.3 includes a clause for identifying when the plan is implemented. No change made.

2. The SDT refers the commenter to Measure M2 which clearly states that a hard copy or electronic copy is sufficient evidence. No change made.

3. The SDT believes that the example cited is a situation that would impact the Operating Plan. The suggested wording change does not provide any additional clarity. Requirement R5, part 5.1 already says what the commenter is proposing. No change made.

4. The standard states that an entity must be in a position to maintain compliance with all applicable Reliability Standards. Failure to maintain this compliance should be the indicator of when action must be taken. Additionally, Requirement R1, part 1.6.3 includes a clause for identifying when the plan is implemented. No change made.</td></tr>
<tr><td>SERC OC Standards Review Group</td><td>Yes</td><td>In the context of R1, section 1.2, how much redundancy is required? Does every RTU require two completely independent communication circuits, one to the primary and one to the backup control center? We suggest that the drafting team draft language which is much more specific in defining the redundant requirement by only the control center and its associated and concentrated data paths, e.g., something like “the backup center shall not be dependent upon any capability contained within the primary control center”. We believe that silence on the issue of required levels of redundancy down to the detail level including RTUs or communication circuits will cause serious and unnecessary conflicts with the compliance function.

The proposed revisions to R3 and R4 should have also included clarifying language to address the issue of whether or not tertiary facilities are required in the event of a planned outage of the primary or secondary facility in excess of two weeks. The SDT’s responses to previous comments on this issue are inadequate in that they are essentially providing an interpretation that is based upon the SDT’s own expectations and assumptions and which has no foundation in anything written in the proposed standard. We therefore suggest adding language similar to the SDT response to previous comments in these requirements. Our suggested wording would read “If a planned outage is expected to take more than the two weeks the affected entity shall develop an acceptable plan with their Regional Entity”.

R5.1: We suggest adding the word “functional” in front of the word “Capabilities.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
South Carolina Electric and Gas	Yes	In the context of R1, section 1.2, how much redundancy is required? Does every RTU require two completely independent communication circuits, one to the primary and one to the backup control center? We suggest that the drafting team draft language which is much more specific in defining the redundant requirement by only the control center and its associated and concentrated data paths, e.g., something like "the backup center shall not be dependent upon any capability contained within the primary control center". We believe that silence on the issue of required levels of redundancy down to the detail level including RTUs or communication circuits will cause serious and unnecessary conflicts with the compliance function. The proposed revisions to R3 and R4 should have also included clarifying language to address the issue of whether or not tertiary facilities are required in the event of a planned outage of the primary or secondary facility in excess of two weeks. The SDT's responses to previous comments on this issue are inadequate in that they are essentially providing an interpretation that is based upon the SDT's own expectations and assumptions and which has no foundation in anything written in the proposed standard. We therefore suggest adding language similar to the SDT response to previous comments in these requirements. Our suggested wording would read "If a planned outage is expected to take more than the two weeks the affected entity shall develop an acceptable plan with their Regional Entity". R5.1: We suggest adding the word "functional" in front of the word "Capabilities".
Response: R1 – Part 1.2 does not tell an entity how to accomplish anything. It is simply asking for a description of how it is done. Requirement R6 states that primary and backup functionality can not depend on each other for any aspect of operations required to maintain compliance with all applicable Reliability Standards. How an entity accomplishes that is up to them. No change made. R3 & R4 – The SDT felt that a timeframe was essential with respect to planned outages to the backup functionality otherwise an entity could have its backup functionality out of service under a planned condition indefinitely. This would create a major gap within the standard. The two week timeframe was considered a reasonable timeframe for planned outages by the SDT. No change made R5.1 – The SDT has changed 'in capabilities' to 'to any part of the Operating Plan' to accommodate your concern. **Requirement R5, part 5.1** - An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.		
NPCC Regional Standards Committee	Yes	NPCC RSC participating members suggest that "ensure" should not be used in the Standard. The use of "ensure" implies a guarantee in words, rather than actions.
Response: The SDT agrees that no single entity can ensure the reliability of the entire BES and has replaced that phrase with 'continues to meet their functional obligations with regard to the reliable operation of the BES…'. **R1**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it		

Organization	Yes or No	Question 6 Comment
continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum:		
Southern Company Transmission	Yes	o R1.5 It is recommended that the timing associated with the transition period required in 1.5 be included into 1.6 as part of the Operating Process that is required there. Defining the existence of a "transition period" does nothing to improve reliability unless its tied to the actions of the Operating Process. Recommend R1.6 be changed to the following and R1.5 be eliminated (changes to SDT version shown in italics): "An Operating Process describing the actions (activities and expected time to completion) to be taken during a transition period of less than or equal to two hours between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1 part 1.2......" o In R3 and R4, add the word "normally" as shown to the phrases "...for maintaining compliance with all Reliability Standards that normally depending on..." o Recommend for emphasis and logical flow of the EOP-008 Standard, that requirement R6 which established requirement for independence of primary and be made R1 and then perhaps follow that with R3 and R4 being made R2 and R3 respectively. o The term "capabilities" in R6 may be clarified and avoid future questions or interpretation requests if it references the elements identified in R1.2. For example: "...shall have primary and backup capabilities as described in R1.2 that do not depend on each other....." o In R7, what is the measurable expectation of "demonstrates" - actually performing all control, monitoring, alarming, data movement, voice communications, etc. exclusively from the backup facility for the whole two hour period of 7.2 or observing and recording the capability of the backup's functionality while maintaining master control and operations at the primary facility. From a compliance audit consistency perspective this needs to be clarified either in the standard or in the measure for R7
Response: 1.5 – The SDT does not see that the suggested change adds any clarity to the standard. No change made. R3/4 – The SDT does not agree with the addition of 'normal' as it is undefined, does not add any clarity, and would add confusion to the situation. No change made. R6 order – The SDT believes that plan comes first and at this point in time is not entertaining changes to the order of the requirements. Changing the order does not change the need to comply. No change made. R6 – The suggested change appears to be redundant and unnecessary to the SDT as this requirement is part of the standard which must be taken as a whole. No change made. R7 – Part 7.2 requires a demonstration of the backup functionality. The SDT does not see any way to do this without actually performing an entity's tasks from		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">the backup functionality so the existing wording is clear and sufficient. No change made.</td></tr>
<tr><td>FirstEnergy</td><td>Yes</td><td>Overall FE supports the Draft 5 version of the EOP-008-1 standard. Additionally, we offer the following suggestions:

1. We believe the SDT should replace the phrase "backup capabilities" with "backup functionality" in Requirements R6 and R8. Since the title of this standard is "Loss of Control Center Functionality", and since other requirements in the standard use the phrase "backup functionality", the use of "functionality" should be consistent throughout the standard.

2. FE has not previously raised the question related to certified operators in R3 and R4. See our response to Question 3. We would appreciate the drafting team's perspective and consideration of our comment.

Regarding the "Regional Entity" mentioned in R8 and Sec. D1.1, we assume this to mean organizations such as FRCC, RFC, SERC, etc. Although a minor issue, we note that this capitalized term is not defined in the NERC Glossary or the latest version of the Function Model (Ver. 5). Additionally, there seems to be a move afoot in project 2010-08 "Functional Model Glossary Revisions" to deemphasize the Regional Entity since it was not contained within the SAR scope of that project. In reviewing the project 2010-08 scope, it seems implied to FE that the Compliance Enforcement Authority and the Reliability Assurer would be potential replacements for the term Regional Entity throughout the NERC reliability standards. We encourage this drafting team to better understand the vision of using the CEA and RA within the standards and consider their use over the RE as stated in R8.</td></tr>
<tr><td colspan="3">Response: 1. The SDT agrees that “capabilities” should be changed to “functionality” as you have requested.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality.

2. See the response to Q3.

Regional Entity – The SDT is limited to the guidelines issued by the Standards Committee and NERC staff (in applicable documentation) and at this time, Regional Entity is the correct term. The SDT can’t guess as to what might happen in the future. If changes are needed to functional entity terminology in the future, they will be made when such changes are approved by the Board of Trustees and applicable regulatory authorities. No change made.</td></tr>
<tr><td>We Energies</td><td>Yes</td><td>R5.1 is overly broad in specifying “any changes in capabilities described in R1” and overly aggressive in terms of the 60 day requirement to update and approve the operating plan. Recommend an annual requirement to</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
		review, update and approve the plan, and eliminating the verbiage "any changes in capabilities described in R1."
Response: The SDT believes that annual is too long a time period for such an important document and 60 days is a reasonable timeframe. No change made.		
Bonneville Power Administration	Yes	Suggest some revisions to R5/R1 linkage regarding changes in capabilities. (a voice circuit path change transparent to the System operator is not a capability change. i.e. - A Control Center site change or Physical access would be considered a capability change).
Response: The SDT feels that any change that does not impact the functionality does not need to be reported and that the current wording supports this position. No change made.		
Electric Market Policy	Yes	The proposed revisions to R3 and R4 should have also included clarifying language to address the issue of whether or not tertiary facilities are required in the event of a planned outage of the primary or secondary facility in excess of two weeks. The SDT's responses to previous comments on this issue are inadequate in that they are essentially providing an interpretation that is based upon the SDT's own expectations and assumptions and which has no foundation in anything written in the proposed standard. We therefore suggest adding language similar to the SDT response to previous comments in these requirements. Our suggested wording would read "If a planned outage is expected to take more than the two weeks the affected entity shall develop an acceptable plan with their Regional Entity.
Response: The SDT felt that a timeframe was essential with respect to planned outages to the backup functionality otherwise an entity could have its backup functionality out of service under a planned condition indefinitely. This would create a major gap within the standard. The two week timeframe was considered a reasonable timeframe for planned outages by the SDT. No change made		
Midwest ISO Standards Collaborators	Yes	We have identified a few issues that still remain in the standard. (1) In R1, the requirement applies to "Each RC, BA, and TOP and requires each to ensure "reliable operations of the BES". No single entity can ensure the reliability of the BES. Rather these entities ensure the reliability of the BES working together fulfilling their functional obligations. We suggest "ensures reliable operations of the BES" be changed to" "continues to meet their functional obligations". (2) R1, Part 1.2.5 is redundant to the CIP standards because CIP-002 requires an entity to evaluate all of their assets which would include the backup control center/functionality. (3) R1, Part 1.2.1 implies the BA has situational awareness of the BES. Per the functional model, the BA does not see most of the BES except tie line flows, generator outputs and load. This should reflect that the purpose

Organization	Yes or No	Question 6 Comment
		is for the entities to fulfill their functional obligations. (4) The wording “location providing backup functionality” in R2 could be construed to create a de facto requirement to have a backup control center. (5) The wording of R3 should be improved. It essentially makes this requirement dependent on every other RC requirement in every other standard. We suggest the wording should be changed to “Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity’s control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for fulfilling its functional obligations.” (6) The first and fifth bullets under Data Retention create an obligation to retain data for longer than the 3-year audit cycle (“current year and three previous years”). At the end of the current year, four years of data would have to be maintained. We suggest making this a simple sliding three year requirement.

Response: 1. The SDT agrees that no single entity can ensure the reliability of the entire BES and has replaced that phrase with ‘continues to meet their functional obligations with regard to the reliable operation of the BES…’.

> **R1**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum:

2. The SDT believes that physical and cyber security are essential elements of the backup plan. The backup plan must contain how the backup functionality handles physical and cyber security. If an entity has documentation from the CIP standards that covers these issues, they should just reference it in the backup plan. No change made.

3. With the change made to Requirement R1 in response to your comment #1, any perceived problem with compliance should have been resolved. No change made.

4. The SDT does not agree with your interpretation. As described in the requirements, such a location could be through contracted services and not at an owned site. No change made.

5. The SDT agrees with your interpretation and that is exactly what was meant. No change made.

6. The SDT has changed the language for bullets 1 & 5 to simply retain data since the last compliance audit.

> **Data Retention bullet #1** – Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain their dated, current, in force Operating Plan for backup functionality for the time period since its last compliance audit in accordance with Measurement M1.

> **Data Retention bullet #5 -** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to the capabilities described in Requirement R1 in accordance with Measurement M5.

Organization	Yes or No	Question 6 Comment
Upper Peninsula Power Company and Wisconsin Public Service Corp	Yes	With regards to R7, additional verbiage is required to describe an acceptable functionality test. Does a functionality test require the entity to control BES assets from the backup control center or can operators monitor the BES from the backup control center while the primary control center continues to control and monitor the BES. If the functionality test requires the entity to control from the backup control center; is there a level or percentage of control required? Wisconsin Public Service Corp suggests that monitoring the BES in parallel with the primary control center provides adequate demonstration of functionality. Failure to define an adequate functional test will result in the request for interpretations, inconsistent enforcement, and rule making through enforcement. Wisconsin Public Service Corp also request the standard committee explain the safety and reliability significance to the BES of the 2 hour time limit provided in R 1.5 and how lengthening this time period would have a discernable adverse affect on the reliability or safety of the BES. Furthermore; please clarify, would an entity be in violation if they can't get their back-up site fully functional within two hours for any reason? For example, R6 states "primary and backup capabilities that do not depend on each other for the functionality required to maintain compliance with Reliability Standards." To meet this statement, the entity must design a primary and backup control centers that are separated and redundant enough to survive an assumed initiating event. The level of damage should be specified by the drafting teaming, or lacking guidance by the drafting team by the entity itself. If the actual event is more severe than the assumed event and the backup control center is not up and running in two hours, is this a violation of the standard? To assure a consistent and non-capricious enforcement of the standard, these areas need to be further clarified by the drafting team.
Response: R7 – Part 7.2 requires a demonstration of the backup functionality. The SDT does not see any way to do this without actually performing an entity's tasks from the backup functionality so the existing wording is clear and sufficient. No change made. 2 hours – One can never come up with a hard and fast number applicable to all entities that would guarantee the safety and reliability of the BES at all times. This time frame was debated throughout the life of the project through the comment periods. Input from industry commenters was discussed and evaluated by the SDT and the 2 hour timeframe seemed to be the appropriate number to satiisfy industry concerns. No change made. Violation – The 2 hours cited is a design criterion. Each situation is normally reviewed by the Regional Entity in light of the circumstances involved.		
Xcel Energy		none
Consolidated Edison Co. of New York	No	
ERCOT ISO	No	

Organization	Yes or No	Question 6 Comment
Georgia System Operations Corporation	No	
Independent Electricity System Operator	No	
Northeast Utilities	No	
NPCC	No	
Oncor Electric Delivery LLC	No	
PacifiCorp	No	
Pepco Holdings, Inc.	No	
The Empire District Electric Company	No	
US Bureau of Reclamation	No	
Manitoba Hydro	No	As answered in individual questions.
PPL Electric Utilities	No	The changes are appropriate clarifications.
Response: Thank you for your 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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008
6. Third posting of revised standard on March 17, 2009
7. Initial ballot posting on September 16, 2009
8. Standards Committee remanded to SDT on November 12, 2009
9. Fourth posting of revised standard on February 4, 2010

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 3Q10. The current draft is the fifth iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit for second attempt at initial ballot posting.	April 2010
2. Submit standard for recirculation balloting.	July 2010
3. Submit standard to BOT.	July 2010
4. Submit to regulatory authorities.	October 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.

5. **Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.1.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.1.2. Data communications.

1.1.3. Voice communications.

1.1.4. Power source(s).

1.1.5. Physical and cyber security

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1 part 1.2. The Operating Process shall include at a minimum:

1.1.6. A list of all entities to notify when there is a change in operating locations.

1.1.7. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.1.8. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup functionality in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality for the time period since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup functionality in accordance with Measurement M8.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's Parts (1.1 through 1.6).	The responsible entity did not have a current Operating Plan for backup functionality.
R2	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3.
R4.	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4.

R#	Lower	Moderate	High	Severe
	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Medium VRF.	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a High VRF.	
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1 continuous hour but	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 0.5 continuous hours.

R#	Lower	Moderate	High	Severe
			more than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish backup functionality for more than nine calendar months after the date when the functionality was lost.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008
6. Third posting of revised standard on March 17, 2009
7. Initial ballot posting on September 16, 2009
8. Standards Committee remanded to SDT on November 12, 2009
9. Fourth posting of revised standard on February 4, 2010

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 3Q10. The current draft is the ~~fourth~~fifth iteration of the revision of the existing standard EOP-008.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit for second attempt at initial ballot posting.	April 2010
2. Submit standard for recirculation balloting.	July 2010
3. Submit standard to BOT.	July 2010
4. Submit to regulatory authorities.	October 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Loss of Control Center Functionality**

2. **Number:** **EOP-008-1**

3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.

5. **Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it ~~ensures~~ continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.1.1. Tools and applications to ensure that ~~operating personnel~~ System Operators have situational awareness of the BES.

1.1.2. Data communications.

1.1.3. Voice communications.

1.1.4. Power source(s).

1.1.5. Physical and cyber security

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1 part 1.2. The Operating Process shall include at a minimum:

1.1.6. A list of all entities to notify when there is a change in operating locations.

1.1.7. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.1.8. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes ~~in~~ ~~capabilities~~ to any part of the Operating Plan described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup ~~capabilities~~functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup ~~capability~~functionality and that anticipates that the loss of primary or backup ~~capability~~functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup ~~capability~~functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to ~~the capabilities~~ any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup ~~capabilities~~functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup ~~capability~~functionality and that anticipates that the loss of primary or backup ~~capability~~functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup ~~capability~~functionality in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

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

~~Not applicable.~~

~~1.3.~~1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.4.~~1.3. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain ~~their~~ its dated, current, in force Operating Plan for backup functionality for the ~~current year and three previous years~~ time period since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the ~~current year and three previous years~~ time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated

within sixty calendar days of any changes to ~~the capabilities~~ any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup ~~capabilities~~functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup ~~capability~~functionality and that anticipates that the loss of primary or backup ~~capability~~functionality would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish backup ~~capability~~functionality in accordance with Measurement M8.

~~1.5.~~1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's Parts (1.1 through 1.6).	The responsible entity did not have a current Operating Plan for backup functionality.
R2	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3.
R4.	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for maintaining compliance with one or	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4.

R#	Lower	Moderate	High	Severe
	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Medium VRF.	more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a High VRF.	
R5.	The responsible entity did not update and approve its ~~approved~~ Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to ~~the capabilities~~ any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its ~~approved~~ Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to ~~the capabilities~~ any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its ~~approved~~ Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to ~~the capabilities~~ any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its ~~approved~~ Operating Plan for backup functionality for more than 90 calendar days after a change to ~~the capabilities~~ any part of the Operating Plan described in Requirement R1.
R6.	N/A	The responsible entity ~~did not have~~ has primary and backup ~~capabilities~~ functionality that do ~~not~~ depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity ~~did not have~~has primary and backup ~~capabilities~~functionality that do ~~not~~ depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity ~~did not have~~has primary and backup ~~capabilities~~functionality that do ~~not~~ depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 0.5 continuous hours.

R#	Lower	Moderate	High	Severe
			backup functionality but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup ~~capability~~functionality and anticipated that the loss of primary or backup ~~capability~~functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish backup ~~capability~~functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup ~~capability~~functionality and anticipated that the loss of primary or backup ~~capability~~functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish backup ~~capability~~functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup ~~capability~~functionality and anticipated that the loss of primary or backup ~~capability~~functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish backup ~~capability~~functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup ~~capability~~functionality and anticipated that the loss of primary or backup ~~capability~~functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish backup functionality for more than nine calendar months after the date when the functionality was lost.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Pool and Pre-ballot Window
May 21–June 21, 2010

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2006-04: Backup Facilities

The proposed standard EOP-008-1 — Loss of Control Center Functionality is posted for a 30-day pre-ballot review **until 8 a.m. Eastern on June 21, 2010**.

Because changes have been made to the standards since the last initial ballot, a new ballot pool will be formed. As a result, members of the previous pool for this project must join this new ballot pool.

Instructions

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx. Members who join the ballot pool to vote on the standard will automatically be entered in a separate pool to participate in the non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). (As a reminder, this new approach for VRFs and VSLs is one of the updates reflected in the most recently approved Reliability Standards Development Procedure.)

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2006-04_BFSDT_Rev1_in@nerc.com.

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

Applicability of Standards in Project

Reliability Coordinators
Transmission Operators
Balancing Authorities

Project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open
June 23–July 6, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2006-04: Backup Facilities

An initial ballot window for EOP-008-1 — Loss of Control Center Functionality is now open **until 8 p.m. Eastern on July 6, 2010**.

In addition to voting on the standard, members of the ballot pool will be able to vote in a concurrent non-binding poll on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) associated with the standard. Members who joined the ballot pool to vote on the standard were automatically entered in a separate pool to participate in the non-binding poll for the VRFs and VSLs. The non-binding poll will appear in your list of current ballots, and is labeled accordingly. (As a reminder, this new approach for VRFs and VSLs is one of the updates reflected in the recently FERC-approved Reliability Standards Development Procedure — Version 7.)

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

Project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Non-binding Poll Name:	**Project 2006-04 - Backup Facilities Revision 1 - Non-binding Poll for VRFs and VSLs**
Poll Period:	6/23/2010 - 7/6/2010
Total # Opinions:	221
Total Ballot Pool:	274
Summary Results:	81% of those who registered to participate provided an opinion; 79% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	John J. Moraski	Abstain	View
1	BC Transmission Corporation	Gordon Rawlings		
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins		
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Daniel Brotzman	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	John K Loftis	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett		
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Negative	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

1	Lake Worth Utilities	Walt Gill	Negative	View
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Abstain	
1	Oncor Electric Delivery	Michael T. Quinn		
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Abstain	
1	PacifiCorp	Mark Sampson	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa		
1	Sierra Pacific Power Co.	Richard Salgo		
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens		
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

1	Western Area Power Administration	Brandy A Dunn	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom	Abstain	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl		
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Negative	View
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Abstain	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Negative	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John Bos	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	OTP Wholesale Marketing	Bradley Tollerson	Affirmative	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	View
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li		
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

5	Amerenue	Sam Dwyer	Negative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	City of Tallahassee	Alan Gale	Abstain	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Conectiv Energy Supply, Inc.	Kara Dundas		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Christy Wicke		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Thomas J Trickey	Negative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Nebraska Public Power District	Jon Sunneberg	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Otter Tail Power Company	Ward Uggerud	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis		
5	PSEG Power LLC	David Murray	Abstain	
5	Reedy Creek Energy Services	Bernie Budnik	Negative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Abstain	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	

6	Bonneville Power Administration	Brenda S. Anderson		
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard	Abstain	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Abstain	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		

9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		

Ballot Results	
Ballot Name:	Project 2006-04 - Backup Facilities - Revision 1_in
Ballot Period:	6/23/2010 - 7/6/2010
Ballot Type:	Initial
Total # Votes:	244
Total Ballot Pool:	274
Quorum:	89.05 % The Quorum has been reached
Weighted Segment Vote:	79.45 %
Ballot Results:	The standard will proceed to recirculation ballot.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	81	1	53	0.768	16	0.232	1	11
2 - Segment 2.	10	0.9	9	0.9	0	0	1	0
3 - Segment 3.	64	1	43	0.796	11	0.204	2	8
4 - Segment 4.	17	1	9	0.643	5	0.357	1	2
5 - Segment 5.	46	1	29	0.725	11	0.275	2	4
6 - Segment 6.	36	1	24	0.727	9	0.273	1	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.5	3	0.3	2	0.2	1	0
9 - Segment 9.	6	0.5	5	0.5	0	0	0	1
10 - Segment 10.	8	0.6	6	0.6	0	0	0	2
Totals	**274**	**7.5**	**181**	**5.959**	**54**	**1.541**	**9**	**30**

Individual Ballot Pool Results

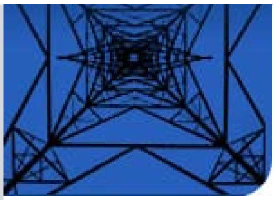
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Affirmative	View
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		

1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Daniel Brotzman	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Negative	
1	Dominion Virginia Power	John K Loftis	Negative	View
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	View
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Negative	
1	Lake Worth Utilities	Walt Gill	Negative	View
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa		
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	

1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens		
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources Services	Michael F Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Negative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John Bos	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	OTP Wholesale Marketing	Bradley Tollerson	Affirmative	

3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li		
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Conectiv Energy Supply, Inc.	Kara Dundas		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Thomas J Trickey	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Nebraska Public Power District	Jon Sunneberg	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Otter Tail Power Company	Ward Uggerud	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Negative	View
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Negative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	

5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	View
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan R. Johnson	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	View
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	



10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2006-04: Backup Facilities

The initial ballot for EOP-008-1 — Loss of Control Center Functionality ended on July 6, 2010.

Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 89.05 %
Approval: 79.45 %

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Violation Risk Factor (VRF) and Violation Severity Level (VSL) Non-binding Poll Results

For the non-binding poll, 81% of those registered to participate provided an opinion; 79% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps

As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments.

Project Background

The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

More information is available on the project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

Consideration of Comments on Initial Ballot — Project 2006-04 — Backup Facilities — Non-binding Poll for VRFs and VSLs
Date of Initial Ballot: June 23, 2010 – July 6, 2010

Summary Consideration: The comments on VRF and VSL have been answered and the only change made was to add the word, "six" as a qualifier for the following VSLs for EOP-008-1:

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's six Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's six Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's six Parts (1.1 through 1.6).	The responsible entity did not have a current Operating Plan for backup functionality.

If you feel that the drafting team overlooked your comments, 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 Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy supports the VRF and VSL for standard EOP-008-1 and is casting an Affirmative vote with the following suggestion: - with respect to the VRF for Requirement R8: The team may want to reconsider the assignment of a "Medium" VRF for this requirement and change it to "Lower". When comparing this requirement to others in the standard that are deemed medium risk it would appear the this requirement is much less of a risk to the BES since it merely requires a plan be sent to its Regional Entity of a loss of functionality that will last for more than six months.
Kevin Querry	FirstEnergy Solutions	3	Affirmative	
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	
Response: The SDT appreciates your support but disagrees with the concept that the VRF for Requirement R8 should be low. This is not just a simple administrative task but a key element in a defense in depth strategy for providing a way to get back to 'normal' operating conditions. No change made.				
Walt Gill	Lake Worth Utilities	1	Negative	1.1.6 states "A list of all entities to notify when there is a change in operating location". This can be interpreted as needing to maintain a list of all entities and then requiring notification

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Brad Chase	Orlando Utilities Commission	1	Negative	of all entities when a change of locations is necessary. We are sure that is not what the Drafting Team intends. The bullet should clarify which entities to list and notify, e.g., (1) the RC, (2) all neighboring (i.e., bordering) BAs and TOPs (for an RC, neighboring RCs as well), and (3) all GOPs, TOPs, BAs, LSEs and DPs within the operating area of the Responsible Entity. 5.1 states "An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1." This can be interpreted as applying to any minor change, which is not the intent of the Drafting Team as reflected in their response to comments. FMPA suggests "An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of changes to the Operating Plan specifically described in Requirement R1." The bullets in R1 basically describe things that would constitute a significant change (e.g., 1.1.8 describes "roles", so, if a role changes, i.e., a job title change through a re-organization, that would be a significant change. A change of a specific person filling that role would not be). The Measures (and Data Retention) require "dated" material where such a requirement for "dated" material is not within the requirements themselves. Measures should not have "hidden" requirements within them. If "dated" is a requirement, then the requirement itself needs to include it, otherwise, remove the reference to "dated" in the Measures, or add a "such as ..." in front of it to make it optional. Also, many of the Measures (for instance M5) simply repeat the requirements. Measures are supposed to be examples of evidence, not "shall have evidence", e.g., for M5 "such as version tracking of its Operating Plan or signature approval of its Operating Plan" would be more appropriate. Data retention for M1 is ambiguous, are we to retain just the current version, or all of the superceded versions since the last compliance audit? In general, the data retention phrases could be much simpler by saying something like "retain evidence of compliance since last compliance audit" rather than repeat all the requirements again. The VRF for R3 and R4 under severe should be reworded since all that is being done is repeating the words of the requirement itself, meaning that any violation would be Severe. As currently stated: "The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R3(4)" would apply to any violation of R3 and R4. Hence, as written, all violations of this requirement would be severe since the "Severe" language would make the language under "Lower", "Moderate" and "High" superfluous. FMPA suggests: "two or more High VRFs" for Severe.
Lynne Mila	City of Clewiston	3	Negative	
Kevin McCarthy	City of Clewiston	4	Negative	
Frank Gaffney	Florida Municipal Power Agency	4	Negative	
David Schumann	Florida Municipal Power Agency	5	Negative	

Voter	Entity	Segment	Vote	Comment
Response: Response to comments on 1.1.6, 5.1, Measures, and Data Retention are contained in the general comment report. VRF – The SDT believes that you meant VSL, and not VRF in the first sentence. Given that, the SDT disagrees with the suggested premise. There is a real distinction between the Lower, Moderate, High, and Severe conditions. In the Lower, Moderate, and High conditions, an entity can have the functionality but for whatever reason, they have not supplied all of the functionality to enable them to comply with all of the requirements they are responsible for in the low, medium, or high VRF categories. In the Severe category, the entity has not supplied the backup functionality at all. No change made.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	Not appropriate to have a VSL of high for an administrative item R5.1.
Response: The SDT believes that the VSL for Requirement R5 has been laid out correctly according to the latest guidelines from Compliance. There is a definite gradient in the performance shown that builds to the Severe condition. No change made.				
Kirit S. Shah	Ameren Services	1	Negative	o R1 is to have a PLAN which is “documentation”. The VRF should be low.
Response: The plan is a document but the SDT does not see it as an administrative task. It is far too valuable a tool and as such does not warrant a low VRF. No change made.				
Francis J. Halpin	Bonneville Power Administration	5	Negative	The High VSL for Requirement 4 will not apply to anyone because it contains an "And" criteria for a High VRF, and none of the requirements have a High VRF.
Response: The High VSL will apply as the wording clearly states that the HIGH VRF cited is for all requirements applicable to the entity and not just those in this standard. No change made.				
Liam Noailles	Xcel Energy, Inc.	5	Negative	The term ‘situational awareness’ introduces an ambiguous term that can be widely interpreted (especially between auditor and entity) and result in a gap of the desired goal. If the intent is to simply indicate that compliance with the NERC standards is intended, then state as such. This could also be accomplished through the use of language similar to that used in R4 “...that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator’s primary control center functionality respectively.”
Response: Response to comment is contained in the general comment report.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	The VRF for R3 and R4 under severe should be reworded since all that is being done is repeating the words of the requirement itself, meaning that any violation would be Severe. As currently stated: "The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4" would apply to any violation of R3 and R4. Hence, as written, all violations of this requirement would be severe since the "Severe" language would make the language under "Lower", "Moderate" and "High" superfluous. I suggest: "two or more High VRFs" for Severe.

Voter	Entity	Segment	Vote	Comment
Response: The SDT assumes that you meant VSL. There is a real distinction between the Lower, Moderate, High, and Severe conditions. In the Lower, Moderate, and High conditions, an entity can have the functionality but for whatever reason, they have not supplied the functionality to enable them to comply with the requirements they are responsible for in the low, medium, or high VRF categories. In the Severe category, the entity has not supplied the backup functionality at all. No change made.				
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Negative	The VSLs for R3 and R4 both simaliary state: "..but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the entity that depend on the primary control center functionality". The requiremnts states that the backup control center is top provide provide the functionality required for maintaing compliance with all standards... The requirement is based on Standards but the VSL is based on requirements. This will lead to confusion since entities look at VSLs along with staandards in order to self audit their compliance program. The written requirement needs to match the VSL.
Response: The SDT believes that the requirements wording and the VSL wording are correct and that the proper distinctions have been made so that there will be no confusion. Furthermore, standards consist of requirements and it is the requirements to which an entity must comply. No change made.				
George T. Ballew	Tennessee Valley Authority	5	Negative	TVA offers the following comments for rev 1 to EOP-008. R1. 1.3 consistent ? identical R3. And R4. Implies that for a planned loss of primary or backup functionality lasting longer than two weeks, a tertiary facility is required. This seems to be in conflict and much more restrictive than requirement R8. which states that for real losses anticipated to last longer than 6 months the RC, BA or TO has 6 months from the time of the loss to provide a plan to its Regional Entity. R5. "any changes" is a very broad requirement open to interpretation by a auditor. This is a potential violation waiting to happen. Need to use plain language that is more clear and concise in these standards. R7. How do you document backup functionality? By testing every possible function? If then intent is to conduct operations for two hours from the backup facility and document , then say just that.
Response: Response to comments on non-VRF/VSL is contained in the general comment report.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	We disagree with the VRF for R8. We believe this should be a Lower VRF because it is primarily an administrative item that requires a long term outage of either the primary or backup control center/functionality. History has shown that a long term outage of either is highly improbable. We agree with the remainder of the VRFs but offer the following comments. We do not agree that EOP-005-2 R1 is similar to EOP-008-1 R1 as identified in the analysis.

Voter	Entity	Segment	Vote	Comment
				The focus seems to be that both requirements require a plan so they must be similar. We believe that you must look at the intent of the plan to determine if requirements are similar. For several of the requirements, a statement was made that there are no similar requirements to compare because the requirement is new. We don't understand how a new requirement might not have a similar existing requirement to compare it to. For the VSLs for R2, we do not believe there should be any Severe VSLs because R2 is an administrative requirement. We are concerned the VSLs for R3 could create a kind of double jeopardy. If a requirement is violated by an RC, there is some probability that the violation will extend to the backup control center as well. Thus, they could be found in violation of the original requirement and EOP-003-1 R3. We are concenred the VSLs for R4 could create a kind of double jeopardy. If a requirement is violated by a BA or TOP, there is some probability that the violation will extend to the backup functionality as well. Thus, they could be found in violation of the original requirement and EOP-003-1 R4.
Response: The SDT disagrees with the concept that the VRF for Requirement R8 should be low. This is not just a simple administrative task but a key element in a defense in depth strategy for providing a way to get back to 'normal' operating conditions. No change made. The SDT agrees that just because a plan is required doesn't make two requirements similar. The intent is the key element to consider. In this case, the SDT believes that the intent is indeed similar and that the linkage is correct. No change made. The SDT agrees that just because a requirement is new in a particular standard that doesn't mean that there isn't a similar requirement in another standard. However, in this case, the SDT researched the existing requirements in other standards and did not find a match. Lacking any specific examples in your comment, the SDT believes that the present wording is correct. No change made. The current wording of the Severe VSL covers the situation where an entity does not have a copy of its Operating Plan for backup functionality at any of its control locations. This covers the primary location. The SDT believes that not having a copy of the plan at the primary location (as well as all other locations) warrants a Severe VSL. No change made. NERC Compliance has repeatedly stated that double jeopardy will not be an issue in evaluating adherence to standards. No change made.				

Consideration of Comments on Initial Ballot — Project 2006-04 — Backup Facilities
Date of Initial Ballot: June 23, 2010 – July 6, 2010

Summary Consideration: An initial ballot was conducted from June 23-July 6, 2010 and achieved a quorum of 89.05% and a weighted segment approval of 79.45%.

The SDT has reviewed and replied to all of the comments received with both affirmative and negative ballots. Several semantic changes will be made as shown below but no significant contextual changes were required. There were no changes to the standard necessary due to those few minority opinions that were received. The SDT believes that the standard is ready for the recirculation ballot.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality.

Data retention - Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.

If you feel that the drafting team overlooked your comments, 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 Vice President and Director of Standards, Herbert Schrayshuen at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	1.1.6 states "A list of all entities to notify when there is a change in operating location". This can be interpreted as needing to maintain a list of all entities and then requiring notification of all entities when a change of locations is necessary. I am sure that is not

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Walt Gill	Lake Worth Utilities	1	Negative	what the Drafting Team intends. The bullet should clarify which entities to list and notify, e.g., (1) the RC, (2) all neighboring (i.e., bordering) BAs and TOPs (for an RC, neighboring RCs as well), and (3) all GOPs, TOPs, BAs, LSEs and DPs within the operating area of the Responsible Entity. 5.1 states "An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1." This can be interpreted as applying to any minor change, which is not the intent of the Drafting Team as reflected in their response to comments. I suggest "An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of changes to the Operating Plan specifically described in Requirement R1. The bullets in R1 basically describe things that would constitute a significant change (e.g., 1.1.8 describes "roles", so, if a role changes, i.e., a job title change through a re-organization, that would be a significant change. A change of a specific person filling that role would not be). The Measures (and Data Retention) require "dated" material where such a requirement for "dated" material is not within the requirements themselves. Measures should not have "hidden" requirements within them. If "dated" is a requirement, then the requirement itself needs to include it, otherwise, remove the reference to "dated" in the Measures. Also, many of the Measures (for instance M5) simply repeat the requirements. Measures are supposed to be examples of evidence, not "shall have evidence", e.g., for M5 "such as version tracking of its Operating Plan or signature approval of its Operating Plan" would be more appropriate. Data retention for M1 is ambiguous, are we to retain just the current version, or all of the superceded versions since the last compliance audit? In general, the data retention phrases could be much simpler by saying something like "retain evidence of compliance since last compliance audit" rather than repeat all the requirements again. The VRF for R3 and R4 under severe should be reworded since all that is being done is repeating the words of the requirement itself, meaning that any violation would be Severe. As currently stated: "The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4" would apply to any violation of R3 and R4. Hence, as written, all violations of this requirement would be severe since the "Severe" language would make the language under "Lower", "Moderate" and "High" superfluous. I suggest: "two or more High VRFs" for Severe.
Brad Chase	Orlando Utilities Commission	1	Negative	
Frank Gaffney	Florida Municipal Power Agency	4	Negative	
David Schumann	Florida Municipal Power Agency	5	Negative	

Voter	Entity	Segment	Vote	Comment
Response: 1.1.6 – Your interpretation of the requirement is correct and is what the SDT intended. The list needs to be specific, not generic. In a time of crisis, an exact list of who to call is required. Operators will have enough to worry about without trying to figure out who to call. The SDT realizes that this is a burden but believes it is a small cost to pay up front if a catastrophe actually occurs. No change made. 5.1 – The suggested wording change does not alter the intent of the SDT, provide any additional clarity, or change the responsibility of the functional entity. By placing the qualifier of those changes described in Requirement R1 in the last iteration, the SDT has constrained the updates to only those items spelled out in the requirement. The SDT believes that if it is important enough to be in the plan, then it is important enough to require updating the plan if the information changes. No change made. Dated – Placing the word 'dated' in a measure does not hide a requirement in the measure. It is good business practice to date any document. The latest guidelines from NERC Compliance clearly encourage the use of 'dated' in measures whenever a document is part of the evidence. No change made. Measures – The SDT believes that it has written the measures in a form that complies with the latest guidelines from NERC Compliance. No change made. Data retention – The SDT believes that the data retention for Measure M1 already stated what was indicated but agrees that the wording may be obscure. A semantic change has been made to provide additional clarity. **Data retention** - Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1. VRF – Response to comments on VRF contained in the VRF/VSL poll comments report.				
Tim Hattaway	PowerSouth Energy Cooperative	5	Negative	Concerned with the requirement concerning updating the plan.
Response: By placing the qualifier of those changes described in Requirement R1 in the last iteration, the SDT has constrained the updates to only those items spelled out in the requirement. No change made.				
Scott Kinney	Avista Corp.	1	Affirmative	Avista is in favor of the revised standard but is concerned with what is meant by "the simulated loss of primary control center functionality" in R7.1. We think this term needs to be defined. If "simulated loss" means the complete shutdown of the primary control center then Avista is really concerned with the risk to reliability. The "simulated loss" is too big of a risk to perform the simulation. Avista feels "simulated loss" shouldn't be defined as complete shutdown of the primary control center but rather placed on standby so the System Operator at the primary center can still take control if necessary during the simulated event.
Response: The SDT believes that 'simulated' means just that and not an actual shutdown. How an entity accomplishes that simulation (standby, parallel operation, etc.) is entirely up to them. No change made.				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Donald S. Watkins</td><td>Bonneville Power Administration</td><td>1</td><td>Negative</td><td rowspan="4">BPA disagrees with the 2 week time limitation in R4 for control center planned outages, believe it should be 3 to 4 weeks.
BPA disagrees with the changes made to Requirement 5.1 and Measure 5.... changing "in capabilities" to "any part of the Operating Plan". It would not make sense to have to approve the plan for a simple telephone circuit re-routing transparent to the plan capability. Suggest modifying the language to state: "An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes in capabilities to any part of the Operating Plan such as a different primary or backup facility described in Requirement R1."
General Comment - The High VSL for Requirement 4 will not apply to anyone because it contains an "And" criteria for a High VRF, and none of the requirements have a High VRF.</td></tr>
<tr><td>Rebecca Berdahl</td><td>Bonneville Power Administration</td><td>3</td><td>Negative</td></tr>
<tr><td>Francis J. Halpin</td><td>Bonneville Power Administration</td><td>5</td><td>Negative</td></tr>
<tr><td>Brenda S. Anderson</td><td>Bonneville Power Administration</td><td>6</td><td>Negative</td></tr>
<tr><td colspan="5">Response: R4 – The SDT has vetted the 2 week time period with the industry through multiple comment periods. Without specific reasoning to support a change to a longer period the SDT cannot justify a change at this point in the process. No change made.
5.1 – The suggested wording change does not alter the intent of the SDT, provide any additional clarity, or change the responsibility of the functional entity. By placing the qualifier of those changes described in Requirement R1 in the last iteration, the SDT has constrained the updates to only those items spelled out in the requirement. The SDT believes that if it is important enough to be in the plan, then it is important enough to require updating the plan if the information changes. No change made.
VSL - Response to comments on VSL contained in the VRF/VSL poll comments report.</td></tr>
<tr><td>Paul Shipps</td><td>Lakeland Electric</td><td>6</td><td>Negative</td><td>Clarification of entities to notify</td></tr>
<tr><td colspan="5">Response: The list needs to be specific. In a time of crisis, an exact list of who to call is required. Operators will have enough to worry about without trying to figure out who to call. The SDT realizes that this is a burden but believes it is a small cost to pay up front if a catastrophe actually occurs. No change made.</td></tr>
<tr><td>James R. Keller</td><td>Wisconsin Electric Power Marketing</td><td>3</td><td>Affirmative</td><td rowspan="2">Comment 1: The May 5, 2010 draft of this standard appears to have errors in numbering in R1.2 (the series that follows is 1.1.1, 1.1.2, ..., 1.1.5). The error is carried through to R1.6 where the series that follows is 1.1.6, 1.1.7, and 1.1.8.
Comment 2: R1.1.1 (sic) Situational awareness is not a NERC defined term and therefore is subject to interpretation. Suggest the SDT add this term to the glossary of</td></tr>
<tr><td>Anthony Jankowski</td><td>Wisconsin Energy Corp.</td><td>4</td><td>Affirmative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Linda Horn	Wisconsin Electric Power Co.	5	Affirmative	NERC terms, using a definition such as: Situational Awareness: Knowing what is going on in the system you control, and having sufficient information to understand what needs to be done to maintain or return to a reliable operating state. Comments 3: The VSLs for R1 are based on the number of missing Parts in R1.1 through R1.6. It is not clear whether Parts with multiple items listed (i.e. 1.2 and 1.6) are potentially additive in terms of the number of missing parts. If this is not the case, it may be a simple matter to state that there is a maximum number of 6 parts to miss.
Response: 1. The SDT agrees that the 'numbering' was in error, and this has been corrected. 2. The concept of situational awareness has been widely used in the electric industry since 2005 where it was used in the blackout reports prepared by NERC and the U.S.-Canada Power System Outage Task Force. In the context of the blackout report, as in standard EOP-008, it means knowing what is going on in the system you control, and having sufficient information to understand what needs to be done to maintain or return to a reliable operating state. Therefore, for each entity, the specific methods and information that would be needed to maintain situational awareness may be different. No change made. 3. (Note - This comment should have been submitted as part of the VRF/VSL poll.) The team added the word, 'six' as proposed for clarity. If an entity misses a 'part' of 1.2, then this would count as missing one 'part.'				
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	While Reclamation chooses to abstain in this vote, we do note that the formatting in this standard will make it difficult to enforce. Specifically the sub requirements section numbers do not conform the numbering convention system used on other standards. Section 1.2 sub requirements are listed as 1.1.x, which implies a requirement 1.1 sub-requirement. Section 1.6 sub requirements are listed as 1.1.6 which appears to be a continuation of the sub-requirement numbering system used under requirement 1.2. Requirement 5 and 7 appear to have the correct sub-requirement numbering convention.
Response: The SDT agrees that the 'numbering' was in error and has been corrected.				
Russell A Noble	Cowlitz County PUD	3	Negative	Cowlitz PUD respectfully disagrees that the use of annual or annually is acceptable. These terms if strictly interpreted as every 365 days will cause "compliance creep," making it difficult to maintain a required activity at a particular time frame (e.g. September) within a calendar year.
Response: 'Annual' is used throughout the Reliability Standards. The common definition of annual from Webster's is: "occurring or happening every year or once a year." The SDT believes that this definition fits the requirement. No change made.				
Michael F Gildea	Dominion Resources Services	3	Negative	Dominion feels compelled to vote negative because the term "any" remains used in requirement R5.1 despite concerns expressed by some stakeholders during this process. The SDT, in response to those comments, stated "However, in this case, "any" is bound by the parts of Requirement R1 which lay out what specific information is required in the Operating Plan. Therefore, in this context, "any" is not too broad and is the appropriate term to use. No change was made. In all due deference to the SDT, we
John K Loftis	Dominion Virginia Power	1	Negative	

Voter	Entity	Segment	Vote	Comment
Mike Garton	Dominion Resources, Inc.	5	Negative	cannot vote in support of the use of a term that is defined as “one, some, or all indiscriminately of whatever quantity: a : one or more -used to indicate an undetermined number or amount have you any money b : all used to indicate a maximum or whole needs any help he can get c : a or some without reference to quantity or extent grateful for any favor at all” when the intent of the SDT is to limit this requirement to changes only to “specific information required in R1”. There is no guarantee that an auditor or anyone else those who reads this requirement without the background information will come to a same conclusion as the SDT. This places undue risk on those entities an entity with an Operating Plan that contains elements other than beyond those listed in R1. Another alternative would be for that entity to develop two a separate plans - one containing only the minimum requirements subject to compliance and another containing the additional elements. placing these additional elements in this separate plan. We don’t believe this best serves reliability and are disappointed that the SDT didn’t take this opportunity to clarify language when it was obvious that there was not a universal understanding of the intent of the requirement as written.. Dominion could support this standard if a simple change were made to R5.1 so that it reads “An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan covering one of the minimum requirements listed under Requirement R1.”
Louis S Slade	Dominion Resources, Inc.	6	Negative	
Response: The suggested wording change does not alter the intent of the SDT, provide any additional clarity, or change the responsibility of the functional entity. By placing the qualifier of those changes described in Requirement R1 in the last iteration, the SDT has constrained the updates to only those items spelled out in the requirement. The SDT believes that if it is important enough to be in the plan, then it is important enough to require updating the plan if the information changes. No change made.				
Douglas E. Hils	Duke Energy Carolina	1	Affirmative	Duke Energy appreciates the work of the SDT on this. With our affirmative vote we have the following suggested corrections: - in the Applicability section, 4.1.1 and 4.1.3 are not indented the same as 4.1.2; - the numbering of sub-bullets under R1.2 is incorrect, and should be 1.2.1, 1.2.2, etc. - Likewise, numbering of sub-bullets under R1.6 should be 1.6.1, 1.6.2, etc. Thank you.
Response: 4.1.1 – The SDT agrees and the appropriate correction has been made. 1.2 – The SDT agrees that the ‘numbering’ was in error and this has been corrected. 1.6 – The SDT agrees that the ‘numbering’ was in error and this has been corrected.				

Voter	Entity	Segment	Vote	Comment
Stanley M Jaskot	Entergy Corporation	5	Negative	Entergy will be voting against this standard because we do not propose the 2-hour staffing requirement.
Terri F Benoit	Entergy Services, Inc.	6	Negative	The proposed minimum staffing time to fully activate and staff our Back-up Control Center is three (3) hours.
Response: The SDT has vetted the 2 hour time period with the industry through multiple comment periods. If the 2 hour time frame can't be met with the existing plan, the SDT has proposed a 24 month implementation plan to allow entities to achieve compliance with the new standard. No change made.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy supports standard EOP-008-1 and is casting an Affirmative vote with the following suggestion with respect to Requirement R8 which states "Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup capability functionality and that anticipates that the loss of primary or backup capability functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish backup capability functionality.": Regarding the phrase "how it will re-establish backup capability functionality" at the end of the requirement, we suggest it be changed to "how it will re-establish primary or backup capability functionality" which would be consistent with the rest of the requirement.
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	
Response: The SDT agrees and has made the suggested semantic change. **R8**. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality.				
Kirit S. Shah	Ameren Services	1	Negative	o R1 is to have a PLAN which is "documentation". The VRF should be low. o R.5.1, SDT should ask the entity to list the assumptions that support the 2 hours; otherwise it might become a violation/performance obligation if an actual emergency takes more than 2 hours. We believe that the plan should be reasonably likely to be effected in 2 hour transition but force majeure may pre-empt actual performance. o In R4, the second line, the "applicable certified operators" would be served to mirror the language in the PER standard NERC-certified operating personnel and we would add appropriate rather than applicable and add a parenthetical (e.g TOP functionality to be provided by a NERC TOP or RC certified operator). It would be illogical to say that since we are RC certified but we are doing TOP function, that we wouldn't be

Voter	Entity	Segment	Vote	Comment
				"applicable". Said another way, applicable or higher, conceptually should apply.
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	R1 is to have a PLAN which is "documentation". The VRF should be low. R1.5.1, SDT should ask the entity to list the assumptions that support the 2 hours; otherwise it might become a violation/performance obligation if an actual emergency takes more than 2 hours. The plan should be reasonably likely to be effected in 2 hour transition but force majeure may pre-empt actual performance. In R4, the second line, the "applicable certified operators" would be served to mirror the language in the PER standard NERC-certified operating personnel and we would add appropriate rather than applicable and add a parenthetical (e.g TOP functionality to be provided by a NERC TOP or RC certified operator).
Response: VRF – Response to comments on VRF contained in the VRF/VSL poll comments report. 5.1 – The SDT assumes that you meant Requirement R1, part 1.5, and not R5.1. The SDT believes that an entity should plan to transition in the 2 hour timeframe. No change made. R4 – The SDT believes that the term 'applicable' accomplishes exactly what you suggest in far fewer words. No change made.				
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	R1. 1.3 consistent ? identical R3. And R4. Implies that for a planned loss of primary or backup functionality lasting longer than two weeks, a tertiary facility is required. This seems to be in conflict and much more restrictive than requirement R8. which states that for real losses anticipated to last longer than 6 months the RC, BA or TO has 6 months from the time of the loss to provide a plan to its Regional Entity. R5. "any changes" is a very broad requirement open to interpretation by a auditor. This is a potential violation waiting to happen. Need to use plain language that is more clear and concise in these standards. R7. How do you document backup functionality? By testing every possible function? If then intent is to conduct operations for two hours from the backup facility and document , then say just that. Test the plan annually, how often do we test the functionality of the backup facilities?
George T. Ballew	Tennessee Valley Authority	5	Negative	
Response: 1.3 – The SDT assumes that you meant to replace the word 'consistent' with 'identical'. The SDT believes that there are some functions in a primary control center that do not have to be duplicated at a backup facility in order to maintain compliance with the Reliability Standards and therefore, the use of the term 'identical' is not appropriate. No change made. R3/4 – The SDT does not see any conflict between Requirements R3 & R4 and Requirement R8. Planned outages indicate a degree of control where you can determine the length of the outage and plan accordingly. The 2 week time period is a reasonable limit for most situations that the SDT could come up with. With an unplanned outage, you have no (or little) control over the initiation or length of the outage. The SDT felt that it would be unreasonable to place a hard and fast time limit on unplanned outages as any time limit could eventually lead to requiring a tertiary system. Therefore, no time limit was				

Voter	Entity	Segment	Vote	Comment
placed in Requirements R3 & R4 and a six month time limit for a plan was established in Requirement R8 following a catastrophic situation. No change made. R5 – By placing the qualifier of those changes described in Requirement R1 in the last iteration, the SDT has constrained the updates to only those items spelled out in the requirement. The SDT believes that if it is important enough to be in the plan, then it is important enough to require updating the plan if the information changes. No change made. R7 – Requirement R7 does not mandate that an entity document backup functionality but rather that an entity document the results of the backup test. The requirement clearly states that the test must be done on an annual basis. No change made.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	The R5.1 sixty day requirement threshold for "any" change subjects an entity to a high VSL for administrative issues that don't impact the Bulk Electric System. This is inappropriate and unnecessarily if the plan lists relevant information that is useful, and specific but might not affect the plan or Bulk Electric System reliability. R5.1 should be deleted in its entirety. If not deleted, R5.1 should be clarified to drop "any" and include only "changes that affect BES functionality".
Terry Harbour	MidAmerican Energy Co.	1	Negative	
Response: VSL – Response to comments on VSL contained in the VRF/VSL poll comments report. 5.1 – The suggested wording change does not alter the intent of the SDT, provide any additional clarity, or change the responsibility of the functional entity. By placing the qualifier of those changes described in Requirement R1 in the last iteration, the SDT has constrained the updates to only those items spelled out in the requirement. The SDT believes that if it is important enough to be in the plan, then it is important enough to require updating the plan if the information changes. No change made.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	The standard is still very vague as to wether data centers that supply information to primary and backup control facilities have to be redundant. The requirement should be clear.
Response: The SDT believes that they have made the requirement as clear as possible within the scope and purpose of the standard. Specific configurations of monitoring and control systems are beyond the scope of the SDT. No change made.				
Michael Ibold	Xcel Energy, Inc.	3	Negative	The term 'situational awareness' introduces an ambiguous term that can be widely interpreted (especially between auditor and entity) and result in a gap of the desired goal. If the intent is to simply indicate that compliance with the NERC standards is intended, then state as such. This could also be accomplished through the use of language similar to that used in R4 "...that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively."
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
Response: The concept of situational awareness has been widely used in the electric industry since 2005 where it was used in the blackout reports				

Voter	Entity	Segment	Vote	Comment
prepared by NERC and the U.S.-Canada Power System Outage Task Force. Therefore, for each entity, the specific methods and information that would be needed to maintain situational awareness may be different. No change made.				
Terry Volkmann	Volkmann Consulting, Inc.	8	Negative	This standard does not consider the impact to the BES in requiring a BU CC. The Version 4 of the CIP standards, presently in development, considers size when determining applicabily of most of the CIP requirements. For most of the CIP requirements to be applicable, an entity needs to operate higher than 100kv (East) or be larger than 1000 MW.s It seems appropriate for a similar requirements to be in place for requiring a BU CC.
Response: The SDT has allowed for contracted services for Transmission Operators and Balancing Authorities which should alleviate concerns over the size of an entity and the impact of the standard. No change made.				

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008
6. Third posting of revised standard on March 17, 2009
7. Initial ballot posting on September 16, 2009
8. Standards Committee remanded to SDT on November 12, 2009
9. Fourth posting of revised standard on February 4, 2010
10. Initial ballot June 23, 2010 to July 6, 2010

Proposed Action Plan and Description of Current Draft:
The drafting team made some minor clarifying changes to the standard following the initial ballot. This is the sixth version of the standard and is being posted for a recirculation ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit standard for recirculation balloting.	July 15-24, 2010
2. Submit standard to BOT.	August 4, 2010
3. Submit to regulatory authorities.	TBD

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title: Loss of Control Center Functionality**
2. **Number: EOP-008-1**
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.
5. **Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Voice communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include at a minimum:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's six Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's six Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's six Parts (1.1 through 1.6).	The responsible entity did not have a current Operating Plan for backup functionality.
R2	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3.
R4.	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4.

R#	Lower	Moderate	High	Severe
	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Medium VRF.	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a High VRF.	
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 0.5 continuous hours.

R#	Lower	Moderate	High	Severe
			for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

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. Version 1 of SAR posted for comment from November 6, 2006 to December 5, 2006
2. Version 2 of the SAR posted for comment from February 15, 2007 to March 16, 2007
3. SAR approved on April 30, 2007
4. First posting of revised standard on February 7, 2008
5. Second posting of revised standard on August 26, 2008
6. Third posting of revised standard on March 17, 2009
7. Initial ballot posting on September 16, 2009
8. Standards Committee remanded to SDT on November 12, 2009
9. Fourth posting of revised standard on February 4, 2010
10. Initial ballot June 23, 2010 to July 6, 2010

Proposed Action Plan and Description of Current Draft:
The drafting team made some minor clarifying changes to the standard following the initial ballot. This is the sixth version of the standard and is being posted for a recirculation ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit standard for recirculation balloting.	July 15-24, 2010
2. Submit standard to BOT.	August 4, 2010
3. Submit to regulatory authorities.	TBD

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title: Loss of Control Center Functionality**
2. **Number: EOP-008-1**
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Reliability Coordinator.

   4.1.2. Transmission Operator.

   4.1.3. Balancing Authority.
5. **Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include the following, at a minimum: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

1.1. The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality.

1.2. A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum:

1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.

1.2.2. Data communications.

1.2.3. Voice communications.

1.2.4. Power source(s).

1.2.5. Physical and cyber security.

1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.

1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.

1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include at a minimum:

1.6.1. A list of all entities to notify when there is a change in operating locations.

1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality.

1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.

M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

M8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in force Operating Plan for backup functionality ~~for the time period~~ plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in force copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it's backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator's primary control center functionality respectively in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in force Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in force since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current year and one previous year, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in force document and any such documents in force since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1.	The responsible entity had a current Operating Plan for backup functionality but the plan was missing one of the requirement's six Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing two of the requirement's six Parts (1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality but the plan was missing three or more of the requirement's six Parts (1.1 through 1.6).	The responsible entity did not have a current Operating Plan for backup functionality.
R2	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Lower VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a Medium VRF.	The Reliability Coordinator has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 but it did not provide the functionality required for maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the Reliability Coordinator that depend on the primary control center functionality and which have a High VRF.	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3.
R4.	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity has backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 but it did not include monitoring, control, logging, and alarming sufficient for	The responsible entity ~~-~~does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4.

R#	Lower	Moderate	High	Severe
	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Lower VRF.	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a Medium VRF.	maintaining compliance with one or more of the Requirements in the Reliability Standards applicable to the responsible entity that depend on the primary control center functionality and which have a High VRF.	
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its dated, current, in force Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Lower VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a Medium VRF.	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards applicable for the entity that have a High VRF.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality but the test was for less than 0.5 continuous hours.

R#	Lower	Moderate	High	Severe
			for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
1	TBD	Revisions for Project 2006-04	Major re-write to accommodate changes noted in project file

Standards Announcement

Recirculation Ballot Window Open
July 16–July 26, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2006-04: Backup Facilities
A recirculation ballot window for EOP-008-1 — Loss of Control Center Functionality is now open **until 8 p.m. Eastern on July 26, 2010.**

Instructions
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Recirculation Ballot Process
The Standards Committee encourages all members of the ballot pool to review the consideration of comments submitted with the initial ballots. In the recirculation ballot, votes are counted by exception only — if a ballot pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

Next Steps
Voting results will be posted and announced after the ballot window closes.

Project Background
The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

Project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

Ballot Results

Ballot Name:	Prokect 2006-04 - Backup Facilities - Revision 1_rc
Ballot Period:	7/16/2010 - 7/26/2010
Ballot Type:	recirculation
Total # Votes:	256
Total Ballot Pool:	274
Quorum:	**93.43 % The Quorum has been reached**
Weighted Segment Vote:	85.22 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	81	1	59	0.831	12	0.169	4	6
2 - Segment 2.	10	0.9	9	0.9	0	0	1	0
3 - Segment 3.	64	1	48	0.828	10	0.172	3	3
4 - Segment 4.	17	1	12	0.857	2	0.143	2	1
5 - Segment 5.	46	1	33	0.825	7	0.175	3	3
6 - Segment 6.	36	1	26	0.765	8	0.235	0	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.5	3	0.3	2	0.2	1	0
9 - Segment 9.	6	0.4	4	0.4	0	0	1	1
10 - Segment 10.	8	0.6	6	0.6	0	0	0	2
Totals	**274**	**7.4**	**200**	**6.306**	**41**	**1.094**	**15**	**18**

Individual Ballot Pool Results

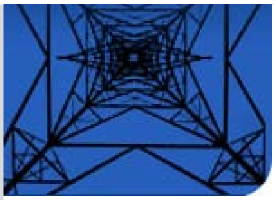
Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	John J. Moraski	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Abstain	View
1	Black Hills Corp	Eric Egge		

1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Abstain	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Daniel Brotzman	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Negative	
1	Dominion Virginia Power	John K Loftis	Affirmative	View
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	View
1	Entergy Corporation	George R. Bartlett	Negative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Elizabeth Howell	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stan T. Rzad	Affirmative	View
1	Lake Worth Utilities	Walt Gill	Abstain	
1	Lakeland Electric	Larry E Watt	Affirmative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Negative	View
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Mark Sampson	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	

1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens		
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
2	Alberta Electric System Operator	Jason L. Murray	Abstain	
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	California ISO	Timothy VanBlaricom	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Bartow, Florida	Matt Culverhouse	Negative	View
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Utility Group	Bryan Y Harper	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources Services	Michael F Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	View
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent	Affirmative	
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	OTP Wholesale Marketing	Bradley Tollerson	Affirmative	

3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Negative	View
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	City of Clewiston	Kevin McCarthy	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Conectiv Energy Supply, Inc.	Kara Dundas		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	View
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Affirmative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Nebraska Public Power District	Jon Sunneberg	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Otter Tail Power Company	Ward Uggerud	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Negative	
5	RRI Energy	Thomas J. Bradish	Affirmative	
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	

5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Negative	View
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	View
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Cleco Power LLC	Matthew D Cripps	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	View
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan R. Johnson	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen	Affirmative	
6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	View
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	North Carolina Utilities Commission	Kimberly J. Jones		
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	



10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement
Final Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2006-04: Backup Facilities
The recirculation ballot for EOP-008-1 — Loss of Control Center Functionality ended July 26, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 93.43%
Approval: 85.22%

The ballot pool approved the standard. Ballot criteria details are listed at the end of the announcement.

Next Steps
The standard will be submitted to the NERC Board of Trustees for approval.

Project Background
The purpose of the standard is to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the "Version 0" standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

Project page: http://www.nerc.com/filez/standards/Backup_Facilities.html

Standards Development Process
The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria
Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net