September 9, 2010

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 No. RM06-16-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition 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 of proposed modifications contained in six Reliability Standards (BAL-002-1 Disturbance Control Performance; EOP-002-3 Capacity and Energy Emergencies; FAC-002-1 Coordination of Plans for New Generation, Transmission, and End-User Facilities; MOD-021-2 Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts; PRC-004-2 Analysis and Mitigation of Transmission and Generation Protection System Misoperations; and VAR-001-2 Voltage and Reactive Control), included below and set forth in **Exhibit A** to this petition. NERC provides these modifications as resolutions to nine outstanding directives from Order No. 693.

Additionally, NERC explains how two additional directives from Order No. 693 have been resolved.

The proposed Reliability Standard modifications were approved by the NERC Board of Trustees during its August 5, 2010 meeting. NERC requests effective dates for FERC-jurisdictional entities as follows:

- MOD-021-1: the first day of the first calendar quarter after FERC approval.
- EOP-002-3, FAC-002-1, and VAR-001-2: the first day of the first calendar quarter, six months after FERC approval.
- BAL-002-1 and PRC-004-2: the first day of the first calendar quarter, one year after FERC approval.

This 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 modifications meet the Commission's directives;
- Modifications to the Reliability Standards, BAL-002-1 (Disturbance Control Performance), EOP-002-3 (Capacity and Energy Emergencies), FAC-002-1 (Coordination of Plans For New Generation, Transmission, and End-User Facilities), MOD-021-2 (Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts), PRC-004-2 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations), and VAR-001-2 (Voltage and Reactive Control), submitted for approval (**Exhibit A**);
- the complete development record of the proposed Reliability Standard modifications (**Exhibit B**); and
- the Response Team roster (**Exhibit C**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/ 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 RELIABILITY CORPORATION	**) Docket Nos. RM06-16-000** **)**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED MODIFICATIONS
TO RELIABILITY STANDARDS BAL-002-1; EOP-002-3; FAC-002-1;
MOD-021-2; PRC-004-2; AND VAR-001-2

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September 9, 2010

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission (the "Commission" or "FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of the Commission's regulations, 18 C.F.R. § 39.5, modifications contained in six Reliability Standards:

- BAL-002-1 (Disturbance Control Performance);
- EOP-002-3 (Capacity and Energy Emergencies);
- FAC-002-1 (Coordination of Plans For New Generation, Transmission, and End-User Facilities);
- MOD-021-2 (Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts);
- PRC-004-2 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations); and
- VAR-001-2 (Voltage and Reactive Control).

On August 5, 2010, the NERC Board of Trustees approved the proposed modifications to BAL-002-1 (Disturbance Control Performance), EOP-002-3 (Capacity and Energy Emergencies), FAC-002-1 (Coordination of Plans For New Generation, Transmission, and End-User Facilities), MOD-021-2 (Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts), PRC-004-2 (Analysis and Mitigation of Transmission and Generation

[1] NERC has been certified by the Commission as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. The Commission 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).
[2] 16 U.S.C. 824o (2010).

Protection System Misoperations), and VAR-001-2 (Voltage and Reactive Control). NERC requests that the Commission approve these proposed modifications to the Reliability Standards and make them effective for FERC-jurisdictional entities as follows:

- MOD-021-1 - the first day of the first calendar quarter after FERC approval.
- EOP-002-3, FAC-002-1, and VAR-001-2 – the first day of the first calendar quarter, six months after FERC approval.
- BAL-002-1 and PRC-004-2 – the first day of the first calendar quarter, one year after FERC approval.

In addition, this filing explains how two directives contained in Order No. 693 (pertaining to Reliability Standards IRO-006-4 and the second directive related to VAR-001-2) have been resolved without modifications to the Reliability Standards.

NERC is also filing the proposed modifications to the Reliability Standards contained herein with applicable governmental authorities in Canada. **Exhibit A** to this filing sets forth the proposed modifications to the Reliability Standards. **Exhibit B** contains the complete record of development for the proposed modifications to the Reliability Standards. **Exhibit C** includes the Response Team roster.

II. NOTICES AND COMMUNICATIONS

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

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*Persons to be included on the Commission's service list are indicated with an asterisk.

III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[3] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, 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 bulk power system in the United States will be subject to the Commission-approved Reliability Standards.

b. Basis for Approval of Proposed Modifications to Reliability Standards

Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes to become

[3] 16 U.S.C. § 824o (2010).

mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective. The Commission has the regulatory responsibility to approve standards that protect the reliability of the bulk power system. In discharging its responsibility to review, approve and enforce mandatory Reliability Standards, the Commission is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> The Commission 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.[4]

When evaluating proposed Reliability Standards, the Commission is expected to give "due weight" to the technical expertise of the ERO and to the technical expertise of a Regional Entity organized on an Interconnection-wide basis with respect to a Reliability Standard to be applicable within that Interconnection. Order No. 672 provides guidance on the factors the Commission will consider when determining whether proposed Reliability Standards meet the statutory criteria.[5]

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED MODIFICATIONS TO THE RELIABILITY STANDARDS

This section summarizes the development of the proposed modifications to the Reliability Standards. These modifications address certain directives contained in Order No. 693. NERC, in its analysis of the proposed modifications to the Reliability Standards, determined that the modifications were just, reasonable, not unduly

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[4] 16 U.S.C. § 824o(d)(2) (2010).

[5] *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").

discriminatory or preferential, and in the public interest. Because these modifications are only incremental changes to existing, FERC-approved Reliability Standards, NERC is not addressing in this filing the justifications for the Commission's previous actions approving the Reliability Standards as mandatory and enforceable. Instead, focus will be on the modifications themselves and the manner in which they address directives contained in Order No. 693.[6]

The complete development record for the proposed modifications to the Reliability Standards is provided in **Exhibit B** and includes the development and approval process, comments received during the industry-wide comment period NERC conducted on the proposed modifications, responses to those comments, ballot information, and NERC's evaluation of the proposed modifications.

Overview of the Process

Following the issuance of the FERC Orders on March 18, 2010, NERC increased its focus on addressing the remaining outstanding directives from FERC Order No. 693. As part of this effort, NERC developed a Standards Authorization Request and set of proposed standard changes to address directives from FERC Order No. 693 that were identified as candidates expected to be less controversial than others. The proposed changes were reviewed and modified by a team of industry experts identified by NERC, then presented for Standards Committee approval. After modifying the proposal to assure the changes did not conflict with the work of existing drafting teams that were nearing project completion, the Standards Committee Executive Committee approved the

[6] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, order on reh'g, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

request in June of 2010. The set of proposed changes were posted for concurrent comment and initial ballot that began on June 18 and concluded on July 14, 2010. The ballot was conducted on a directive-level basis—in essence, a line item ballot. Proposals that did not garner sufficient support as demonstrated by the results of the initial ballot and the comments received were withdrawn from consideration in the recirculation ballot. The team was permitted to make modifications between the initial and recirculation ballots based on comments received to improve the overall quality of the standard. The recirculation ballot occurred from July 21 to 31, 2010. The results were as follows:

- Quorum: 79.66%
- Modifications in BAL-002-1 related to P321 of Order No. 693: 82.4% Approval;
- Concurrence that P577 of Order No. 693 was addressed with IRO-006-4 : 96.6% Approval;
- Modifications in EOP-002-3 related to P582 of Order No. 693: 80.0% Approval;
- Modifications in FAC-002-1 related to P693 of Order No. 693: 80.1% Approval;
- Modifications in MOD-021-2 related to P1300 of Order No. 693: 96.2% Approval;
- Modifications in PRC-004-2 related to P1469 of Order No. 693: 78.9% Approval;
- Modifications in VAR-001-2 related to P1858 of Order No. 693: 74.6% Approval;
- Modifications in VAR-001-2 related to P1879 of Order No. 693: 72.9% Approval;
- Concurrence that the directive in P1879 of Order No. 693 regarding SMA/SoCal Edison needed no change: 72.9% Approval.

The NERC Board of Trustees approved the proposed modifications for filing with the Commission on August 5, 2010.

Modifications Contained in BAL-002-1

In paragraph 321 of Order No. 693, FERC issued two explicit directives:

1. "The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary."

2. "As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor."

The first of these two directives was addressed by simply eliminating the provisions within Requirements R4.2 and R4.6 that allowed for the NERC Operating Committee to modify the Disturbance Recovery Period. However, in reviewing FERC's directive that the ERO should be the entity that modifies the Disturbance Recovery Period as necessary, the Response Team determined that providing NERC with the ability to unilaterally modify the Disturbance Recovery Period would be inconsistent with FERC's principles for approval of a Reliability Standard. The Response Team determined that implementing this directive could effectively result in de-facto modifications to the "clear and objective criterion or measure for compliance" without being developed in an "open and fair" manner. By removing the ability of the NERC Operating Committee to modify the Disturbance Recovery Period from the standard, any such changes, if desired, would only be available through the use of the FERC-approved

Reliability Standards Development Process to modify the standard. This would ensure that the changes to the Disturbance Recovery Period would be subject to full stakeholder review and ultimately Commission approval. While this is an alternative approach to that proposed by the Commission, NERC and its stakeholders believe this to be a superior solution to address the Commission's concerns, because it relies on the statutorily prescribed method for making changes in Reliability Standards.

The second directive was addressed by substituting "Regional Reliability Organization" in the BAL-002-1 Reliability Standard with "Regional Entity" as the Compliance Monitor (currently referred to as the Compliance Enforcement Authority). Similarly, NERC made conforming changes to the Compliance section of the standard. Accordingly, because these changes are largely administrative in nature and consistent with the Commission's directive, NERC respectfully requests Commission approval of the proposed modification to the BAL-002-1 Reliability Standard.

Modifications Contained in EOP-002-3

In paragraph 582 of Order No. 693, FERC issued two explicit directives:

1. Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. (paragraph 579. ISO-NE states that Requirement R2 essentially requires the same actions covered by ISO-NE Operating Procedure No. 4. ISO-NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO-NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO-NE procedures. ISO-NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.)

2. Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.

The first directive was addressed by modifying Requirement R2 of the EOP-002-3 Reliability Standard. The original language of the requirement specified:

> "Each Balancing Authority shall implement its capacity and energy emergency plan when required and as appropriate, to reduce risks to the interconnected system."

In order to make it clear that this requirement did not mandate a full execution of every step in the plan, the language was restructured and additional language added as follows:

> "Each Balancing Authority shall, when required and as appropriate, ~~implement~~ take one or more actions as described in its capacity and energy emergency plan ~~when required and as appropriate~~, to reduce risks to the interconnected system."

The related measure for the standard was also modified to be consistent with the Requirement.

The second directive was addressed by adding measures for Requirements R4, R5, R6, and R7. Similarly, NERC made additional administrative improvements to the Compliance section of the standard, including substituting "Regional Entity" for "Regional Reliability Organization" as the Compliance Monitor (currently referred to as the Compliance Enforcement Authority).

The proposed changes to the EOP-002-3 Reliability Standard are largely administrative in nature and not directly related to the language of any specific requirement. Accordingly, NERC respectfully requests approval of the proposed requirements in compliance with the Commission's directions.

Modifications Contained in FAC-002-1

In paragraph 693 of Order No. 693, FERC issued one explicit directive:

1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.

This directive was addressed by modifying Requirement R1.4 of the FAC-002-1 Reliability Standard. The original language required:

> "Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0."

In order to comply with the directive, the language was modified as follows:

> "Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0."

These changes meet the Commission directive as specified in Order No. 693. No alternative approach was pursued, and language was adopted that directly implements the Commission's suggested modification. Accordingly, no further explanation is necessary.

NERC made additional administrative improvements to the Compliance section of the FAC-002-1 standard, including substituting "Regional Entity" for "Regional Reliability Organization" as the Compliance Monitor (currently referred to as the Compliance Enforcement Authority). Because these changes are administrative in nature and not directly related to the language of any specific requirement, NERC requests Commission approval of the modified FAC-002-1 Reliability Standard.

Modifications Contained in MOD-021-2

In paragraph 1300 of Order No. 693, FERC issued one explicit directive:

1. The Commission directs the ERO to modify the title and purpose statement to remove the word "controllable." We note that no commenter disagrees.

This directive was addressed by modifying the title and purpose statement of the MOD-021-1 standard to remove the word "controllable." NERC made additional administrative improvements to the Compliance section of the standard, including substituting "Regional Entity" for "Regional Reliability Organization" as the Compliance Monitor (currently referred to as the Compliance Enforcement Authority). Accordingly, because these changes are largely administrative in nature and not directly related to the language of any specific requirement, NERC requests Commission approval of the proposed modification to the MOD-021-1 Reliability Standard.

Modifications Contained in PRC-004-2

In paragraph 1469 of Order No. 693, FERC issued two explicit directives:

1. We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.

2. Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.

The first directive was not addressed at this time due to additional complexity beyond what was anticipated.

The second directive was addressed by making modifications to Requirements R1, R2, and R3 of the PRC-004-2 standard to indicate that procedures to be followed related to Corrective Action Plans are specified by the Regional Entity, rather than the

Regional Reliability Organization. Additionally, because PRC-003 is not currently mandatory and enforceable, reference to this standard was removed. While these changes directly modify the requirements in the PRC-004-2 standard, their impacts are largely administrative in nature. The changes do not impose any new burden on any entity, because neither the Regional Entity nor the Regional Reliability Organization are applicable entities under the standard. It is NERC's expectation that the actual procedures used will not change based on the proposed modifications to this standard. Accordingly, no further explanation is necessary.

NERC made additional administrative improvements to the Compliance section of the standard, including the substitution of "Regional Entity" for "Regional Reliability Organization" as the Compliance Monitor (currently referred to as the Compliance Enforcement Authority). Because these changes are largely administrative in nature and not directly related to the language of any specific requirement, NERC requests approval of the proposed modifications to the PRC-004-2 Reliability Standard.

Modifications Contained in VAR-001-2

In paragraph 1858 of Order No. 693, FERC issued one explicit directive:

1. The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.

This directive was addressed by adding "Load Serving Entities" to the standard as applicable entities and making them subject to the same requirements as Purchasing Selling Entities (*i.e.*, R5.). These changes meet the Commission directive as specified in Order No. 693. No alternative approach was pursued, and language was adopted that directly implements the Commission's suggested modification. Accordingly, no further explanation is necessary.

In paragraph 1879 of Order No. 693, FERC issued two explicit directives:

1. The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1.

2. While we [the Commission] affirm[s] this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards. (1877. SMA supports adoption of the proposal to include controllable load as a reactive resource. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements.
   1878. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.)

The first directive was addressed by modifying Requirement R8 of the VAR-001-2 standard to include "controllable load" in the list of examples for reactive resources, and to modify Requirements R2, R5, and R9 to provide similar examples, including "controllable load." These changes meet the Commission directive as specified in Order No. 693. No alternative approach was pursued, and language was adopted that directly implements the Commission's suggested modification.

The second directive was to consider the comments of SMA and SoCal Edison. The comments of SMA, while supportive, did not contain any information that required specific inclusion in the standard. However, to the extent SMA has specific suggestions for improvements to the standard, NERC encourages their participation in the Standards Development Process.

The comments of SoCal Edison reflect a concern regarding the reliability and commercial impacts of the Commission's proposal. NERC does not believe there to be any related negative impacts. The current approved standard already allows for the use of load shedding as a reactive resource as specified in Requirement R8, and should entities participate in voluntary load reductions, rather than involuntary load shedding, NERC does not believe the difference in motive is sufficient to warrant additional cautions beyond that which would accompany any controllable load program.

Consideration of the SMA and the SoCal Edison comments did not result in the conclusion that additional changes were required in the standard. Accordingly, the second directive contained in P1879 of Order No. 693 has been addressed with no specific standards action being taken.

NERC made additional administrative improvements to the Compliance section of the standard, including the substitution of "Regional Entity" for "Regional Reliability Organization" as the Compliance Monitor (currently referred to as the Compliance Enforcement Authority). Because these changes are administrative in nature and not directly related to the language of any specific requirement, NERC respectfully requests Commission approval of the proposed modifications to the VAR-001-2 Reliability Standard.

Directive Addressed Without Additional Standards Modification

In paragraph 577 of Order No. 693, FERC issued one explicit directive:

1. A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.

This directive has been addressed within Reliability Standard IRO-006-4, which was approved by the Commission on March 19, 2009.[7] Accordingly, this directive has been resolved though alternative means equivalent to or more stringent than the solution proposed by the Commission, and modifications to EOP-002 as directed would be duplicative. Making modifications consistent with the Commission's directive in P577 of Order No. 693 would introduce a lack of clarity between the two standards (in the form of potential for double jeopardy), and impede an entity's ability to understand the consequences and range of penalties (monetary and/or non-monetary) for a violation of the standards.

[7] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, 126 FERC ¶ 61,252, (March 19, 2009).

Directives Not Addressed Through This Process

NERC's Order No. 693 project originally identified 37 directives related to 13 standards that appeared to be relatively straightforward to implement. However, as these candidates were considered and reviewed with stakeholders, it quickly became clear that the issues were not as simple as might have been expected. Potential conflicts with established programs in various jurisdictions, as well as the potential costs required to ensure compliance, rapidly created a knot of problems that will require extensive discussions to untangle. Certain of the issues turned out to be more technically complex than they first appeared. The shortened process used also contributed, in some part, to not gaining prompt consensus. Additionally, many entities provided comments regarding their ongoing DSM efforts that show a significant amount of diversity and complexity that will need to be considered as Reliability Standards related to DSM are developed.

It is clear from the comments that the issues are complex and will require significant resources. Thus, it will be important to prioritize the work on the additional directives in the context of all the standards development work NERC has underway.

V. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

NERC initiated the project to address some of the remaining Order No. 693 directives with a Standards Authorization Request on June 2, 2010. Prior to that date, NERC worked with various industry experts to identify directives from Order No. 693 that seemed straightforward to address and then develop draft modifications to the Reliability Standards to address those directives. Changes to 47 different standards were considered during this process. Review of ongoing efforts and discussions regarding the complexity of the effort ultimately led to 13 standards being chosen for modification. The 13 draft standards were developed, and the Standards Authorization Request, the 13 standards, and their implementation plan was posted for comment from June 18, 2010 to July 13, 2010.

NERC's Standards Committee authorized the use of expedited measures from its new process[8] in order to accelerate development of the project. As part of these efforts, an initial ballot of the standards occurred during the last ten days of the comment period. A Response Team, assembled from industry experts and leaders of other NERC standards drafting teams, reviewed all the comments received and ultimately identified six standards that it believed were appropriate to move forward to recirculation ballot. Changes were made to some of the drafts based on comments received in order to achieve greater consensus. These modified standards were posted for recirculation ballot July 21, 2010 through July 31, 2010. All six of the proposed Reliability Standards achieved sufficient quorum and approval to move forward to NERC's Board of Trustees for consideration as industry-approved standards. On August 5, 2010, NERC's Board of Trustees met and approved these proposed modifications to the Reliability Standards for submission to the various regulatory agencies in North America.

NERC recognizes that much work remains to be done on the Order No. 693 directives. NERC is committed to continuing the standards development work on these important issues.

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[8] *See,* Petition of the North American Electric Reliability Corporation for Approval of the Reliability Standard Process Manual Incorporating Proposed Revisions to the Reliability Standards Development Process, Docket No. RR10-12-000 (June 10, 2010). FERC approved NERC's new Standard Process Manual on September 3, 2010. *See, Order Approving Petition and Directing Compliance Filing*, 132 FERC ¶61,200 (Sept. 3, 2010).

VI. **CONCLUSION**

For the reasons set forth above, NERC requests that the Commission approve the proposed modifications to the Reliability Standards and the proposed effective dates, as set forth in this filing.

Respectfully submitted,

/s/ Holly A. Hawkins

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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 9th day of September, 2010.

/s/ Holly A. Hawkins
Holly A. Hawkins

Attorney for North American Electric Reliability Corporation

Exhibit A

Modifications to the Reliability Standards, BAL-002-1 (Disturbance Control Performance), EOP-002-3 (Capacity and Energy Emergencies), FAC-002-1 (Coordination of Plans For New Generation, Transmission, and End-User Facilities), MOD-021-2 (Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts), PRC-004-2 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations), and VAR-001-2 (Voltage and Reactive Control)

Proposed Clean and Redline of BAL-002-1

A. Introduction

1. **Title:** **Disturbance Control Performance**

2. **Number:** BAL-002-1

3. **Purpose:**

   The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)

   4.3. Regional Reliability Organizations

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 90 minutes.

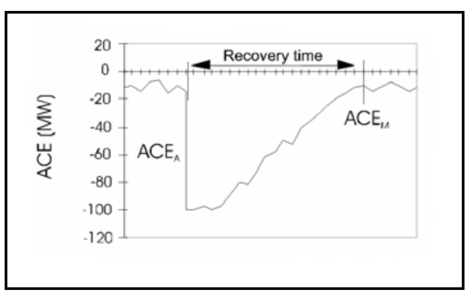
C. Measures

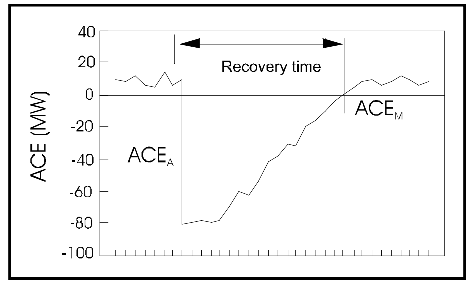
M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:

if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$





if $ACE_A \geq 0$

then

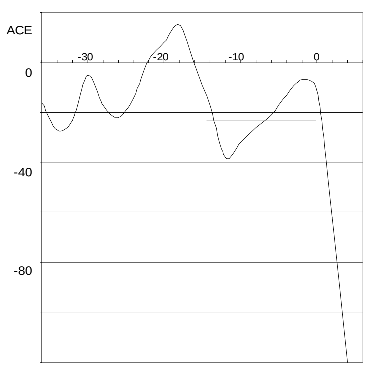
$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

3. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 321.	Revised.

A. Introduction

1. **Title:** **Disturbance Control Performance**

2. **Number:** BAL-002-~~0~~1

3. **Purpose:**

The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)

   4.3. Regional Reliability Organizations

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption. ~~April 1, 2005~~

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All

Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. ~~This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee~~ERO~~.~~

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

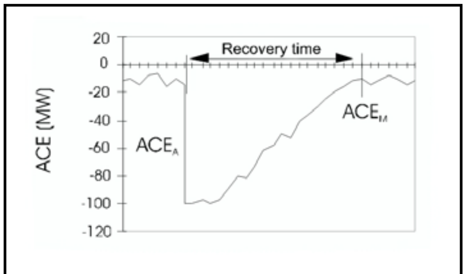
R6.2. The default Contingency Reserve Restoration Period is 90 minutes. ~~This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee~~ERO~~.~~

C. Measures

M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:

if $ACE_A < 0$



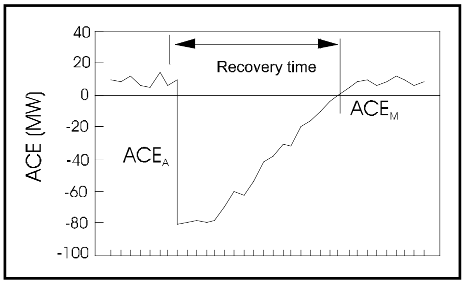
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

if $ACE_A \geq 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

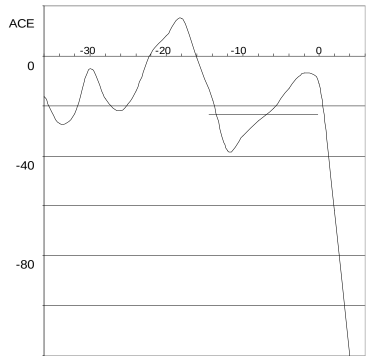


where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional ~~Reliability Organization~~Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

~~1.4.~~1.5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance

Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

3. Violation Severity Levels (no changes)

~~**2.1. Level 1:** Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.~~

~~**2.2. Level 2:** Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.~~

~~**2.3. Level 3:** Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.~~

~~**Level 4:** Value of average percent recovery for the quarter is less than 85%.~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 321.	Revised.

Proposed Clean and Redline of EOP-002-3

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**

2. **Number**: EOP-002-3

3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Reliability Coordinators.

   4.3. Load-Serving Entities.

5. **(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan, , to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 "Transmission Loading Relief Procedure" for explanation of Transmission Service Priorities):

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements one or more actions described in its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 Energy Emergency Alert Levels.

M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

1.3. Not Applicable. **Compliance Monitoring and Enforcement Process**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 8 and 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

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

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

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

1.5. Additional Compliance Information

None.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to “Requirement 6” instead of “Requirement 7”	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. “Applicability.”	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to “2.1”	Errata
2.1	May 13, 2009	FERC Approved	Revised
3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 582.	Revised.

Attachment 1-EOP-002-2.1
Energy Emergency Alerts

Introduction

This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

   1.1. Situations for initiating alert. An Energy Emergency Alert may be initiated for the following reasons:

   - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
   - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 — All available resources in use.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect**.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform

[1] For emergency, not economic, reasons.

the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 **Notification of ATC adjustments**. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 **Availability of generation redispatch options**. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 **Evaluating impact of current transmission loading relief events.** The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 **Initiating inquiries on reevaluating SOLs and IROLs**. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 **Coordination of emergency responses.** The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 **Energy Deficient Entity actions.** Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 **All available generation units are on line**. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 **Purchases made regardless of cost**. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 **Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed**. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 **Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 **Continue actions from Alert 2**. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.

2. All firm and nonfirm purchases were made regardless of cost.

3. All nonfirm sales were recalled within provisions of the sale agreement.

4. Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.

5. Available load reduction programs were exercised (public appeals, voltage reductions, etc.).

6. Operating Reserves being utilized.

Comments:

Reported By:	**Organization:**
Title:	

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**

2. **Number**: EOP-002-~~2.1~~3

3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Reliability Coordinators.

   4.3. Load-Serving Entities.

5. **(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.~~May 13, 2009~~

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, ~~implement~~ take one or more actions as described in its capacity and energy emergency plan, ~~when required and as appropriate~~, to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 "Transmission Loading Relief Procedure" for explanation of Transmission Service Priorities):

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements ~~its~~ one or more actions described in its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes.~~took action to limit its use of Interconnection assistance and that for any unilateral adjustment of generation, it has justification for those adjustments other than attempting to return Interconnection frequency to normal.~~ (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 Energy Emergency Alert Levels.

M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

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

1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable. ~~One or more of the following methods will be used to assess compliance:~~

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

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

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

1.3. Compliance Monitoring and Enforcement Process

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, ~~4~~ 8 and ~~5~~ 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

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

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

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

1.5. Additional Compliance Information

None.

~~**Levels of Non-Compliance for a Reliability Coordinator:**~~

~~following requirements that is in violation:~~

~~Failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities when in an operating Capacity or Energy Emergency (R3).~~

~~One or more of the actions of the Capacity and Energy Emergency Plans were not implemented~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to “Requirement 6” instead of “Requirement 7”	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
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2.1	October 29, 2008	BOT adopted errata changes; updated version number to “2.1”	Errata
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3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 582.	Revised.

Attachment 1-EOP-002-2.1
Energy Emergency Alerts

Introduction
This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

   1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

   - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
   - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 — All available resources in use.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 — Load management procedures in effect.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform

[1] For emergency, not economic, reasons.

the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 **Notification of ATC adjustments**. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 **Availability of generation redispatch options**. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 **Evaluating impact of current transmission loading relief events.** The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 **Initiating inquiries on reevaluating SOLs and IROLs**. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 **Coordination of emergency responses.** The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 **Energy Deficient Entity actions.** Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 **All available generation units are on line**. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 **Purchases made regardless of cost**. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 **Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed**. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 **Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. **Alert 3 — Firm load interruption imminent or in progress**.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 **Continue actions from Alert 2**. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.

2. All firm and nonfirm purchases were made regardless of cost.

3. All nonfirm sales were recalled within provisions of the sale agreement.

4. Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.

5. Available load reduction programs were exercised (public appeals, voltage reductions, etc.).

6. Operating Reserves being utilized.

Comments:

Reported By: **Organization:**

Title:

Proposed Clean and Redline of FAC-002-1

A. Introduction

1. **Title: Coordination of Plans For New Generation, Transmission, and End-User Facilities**

2. **Number:** FAC-002-1

3. **Purpose:** To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Transmission Owner

   4.3. Distribution Provider

   4.4. Load-Serving Entity

   4.5. Transmission Planner

   4.6. Planning Authority

5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.

1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.

1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2.

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

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

1.5. Additional Compliance Information

None

2. Violation Severity Levels (no changes)

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of "Regional Reliability Organizations(s).	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 693.	Revised.

A. Introduction

1. **Title:** **Coordination of Plans For New Generation, Transmission, and End-User Facilities**

2. **Number:** FAC-002-~~0~~ 1

3. **Purpose:** To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Transmission Owner

   4.3. Distribution Provider

   4.4. Load-Serving Entity

   4.5. Transmission Planner

   4.6. Planning Authority

5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.~~April 1, 2005~~

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.

1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.

1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Compliance Monitor: RRO~~Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

~~On request (within 30 calendar days)~~Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

~~1.4.~~1.5. Additional Compliance Information

None

2. Violation Severity Levels (no changes)~~of Non-Compliance~~

~~**2.1. Level 1:** Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Reliability Standard FAC-002_R1.~~

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

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

~~**2.4. Level 4:** Assessments of the impacts of new facilities were not provided.~~

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of "Regional Reliability Organizations(s).	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 693.	Revised.

Proposed Clean and Redline of MOD-021-1

A. Introduction

1. **Title:** **Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts.**

2. **Number:** MOD-021-1

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **(Proposed) Effective Date:** The first day of the first calendar quarter after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees' adoption.

B. Requirements

R1. The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.

R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Transmission Planner and Resource Planner forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible demands, and Direct Control Load Management) are addressed.

M2. The Load-Serving Entity, Transmission Planner and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.

M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

None specified.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels (no changes)

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0.1	April 15, 2009	R1. – comma inserted after Load-Serving Entity	
0.1	December 10, 2009	Approved by FERC — Added effective date	Update
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 1300.	Revised.

A. Introduction

1. **Title:** **Documentation of the Accounting Methodology for the Effects of ~~Controllable~~ Demand-Side Management in Demand and Energy Forecasts.**

2. **Number:** MOD-021-~~0.1~~1

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to ~~controllable~~ Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **(Proposed) Effective Date:** The first day of the first calendar quarter after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees' adoption. ~~December 10, 2009~~

B. Requirements

R1. The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.

R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Transmission Planner and Resource Planner forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible demands, and Direct Control Load Management) are addressed.

M2. The Load-Serving Entity, Transmission Planner and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.

M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Compliance Monitor:~~ Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

None specified.

~~1.4.~~1.5. Additional Compliance Information

None.

2. Violation Severity Levels (no changes) ~~of Non-Compliance~~

~~**2.1. Level 1:** Documentation on the treatment of DSM programs in the demand and energy forecasts was provided, but was incomplete.~~

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

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

~~**2.4. Level 4:** Documentation on the treatment of DSM programs in the demand and energy forecasts was not provided.~~

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0.1	April 15, 2009	R1. – comma inserted after Load-Serving Entity	
0.1	December 10, 2009	Approved by FERC — Added effective date	Update
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 1300.	Revised.

Proposed Clean and Redline of PRC-004-2

A. Introduction

1. **Title:** **Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. **Number:** PRC-004-2

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

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 Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.

A. Introduction

1. Title: **Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. Number: PRC-004-~~1~~2

3. Purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. Applicability

4.1. Transmission Owner.

4.2. Distribution Provider that owns a transmission Protection System.

4.3. Generator Owner.

5. (Proposed) Effective Date: The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.~~August 1, 2006~~

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional ~~Reliability Organization~~Entity's procedures~~ developed for Reliability Standard PRC-003 Requirement 1~~.

~~R1.~~R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional ~~Reliability Organization~~Entity's procedures~~ developed for PRC-003 R1~~.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional ~~Reliability Organization~~Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional ~~Reliability Organization~~Entity's procedures~~ developed for PRC-003 R1~~.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional ~~Reliability Organization~~Entity's procedures~~ developed for PRC-003 R1~~.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional ~~Reliability Organization~~Entity's procedures~~ developed for PRC-003 R1~~.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional ~~Reliability Organization~~Entity's procedures~~ developed for PRC-003 R1~~.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

~~One calendar year.~~ Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

~~1.4.~~1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes) ~~of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:~~

~~**2.1. Level 1:** Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.~~

~~**2.2. Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.~~

~~**2.3. Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.~~

~~**2.4. Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.~~

~~**3. Levels of Non-Compliance for Generator Owners**~~

~~**3.1. Level 1:** Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.~~

~~**3.2. Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.~~

~~**3.3. Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.~~

~~**3.4. Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.

Proposed Clean and Redline of VAR-001-2

A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-2
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators.
   - **4.2.** Purchasing-Selling Entities.
   - **4.3.** Load Serving Entities.
5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption..

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load – within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

R5. Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider.

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[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	TBD	Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised.

A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-~~1~~2
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators.
   - **4.2.** Purchasing-Selling Entities.
   - ~~**4.2.**~~**4.3.** Load Serving Entities.
5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.~~Six months after BOT adoption~~.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;~~ controllable load~~, and~~, if necessary,~~ controllable load ~~load shedding~~ – within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

R5. Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;~~ controllable load~~, and~~, if necessary,~~ controllable load~~load shedding~~ – to satisfy its reactive requirements identified by its Transmission Service Provider.

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[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not limited to, ~~including~~ reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;~~ controllable load~~, and~~, if necessary~~ controllable load~~, load shedding~~ – to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Compliance Monitor shall retain any audit data for three years.

~~1.4.~~1.5. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. ~~Levels of Non-Compliance~~Violation Severity Levels (no changes)

~~**2.1. Level 1:** No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2~~

~~**2.2. Level 2:** There shall be a level two non-compliance if either of the following conditions exists:~~

~~**2.2.1** No evidence to show that directives were issued in accordance with R6.1.~~

~~**2.2.2** No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.~~

~~**2.3. Level 3:** There shall be a level three non-compliance if either of the following conditions exists:~~

~~**2.3.1** Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.~~

~~**2.4. Level 4:** No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.~~

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator	Errata

		Operators" to Applicability section.	
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	TBD	Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised.

Exhibit B

Complete development record of the proposed Reliability Standard modifications

Standard Authorization Request Form

Title of Proposed Standard: Rapid Standards Modifications Responsive to FERC Order 693 Directives		
Request Date: June 2, 2010		
SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: NERC Staff	☐	New Standard
Primary Contact: Andrew Rodriquez, NERC Staff:	☒	Revision to existing Standards (See detailed description)
Telephone: 609-452-8060 **Fax:**	☐	Withdrawal of existing Standard
E-mail: andy.rodriquez@nerc.net	☐	Urgent Action
Purpose: To address directives from FERC Order 693 that are expected to be non-controversial.		
Industry Need: The Commission has expressed concern that industry and NERC have been less responsive than desired in providing a timely resolution to directives contained in FERC Order No. 693. This project would provide an opportunity to demonstrate that the industry and NERC are responsive to FERC directives in a timely fashion.		
Brief Description: In Order No. 693, the Commission issued many directives to modify the Reliability Standards. Several of these directives appear to be less controversial than others. This project is intended to identify those directives and propose modifications to the standards that would address those directives on an expedited basis. This project is not intended to address any controversial issues, and items that are identified through either stakeholder comment or significant opposition (e.g., less than 66 $^{2}/_{3}$ % weighted segment approval) as controversial would be removed from the scope of the project as they are identified.		
Detailed Description: The following paragraphs from FERC Order 693 that have one or more directives that been identified for possible inclusion in this process : 321; 330; 335; 354; 404; 415; 420; 444; 461; 466; 468; 470; 487; 491; 507; 512; 515; 539; 560; 561; 562; 565; 573; 577; 582; 597; 601; 612; 615; 616; 618; 693; 896; 897; 926; 934; 950; 951; 964; 1147; 1148; 1152; 1154; 1155; 1162; 1163; 1177; 1178; 1181; 1184; 1197; 1199; 1200; 1210; 1211; 1212; 1220; 1221; 1232; 1247; 1249; 1250; 1251; 1252; 1254; 1255; 1256; 1264; 1265; 1275; 1276; 1277; 1287; 1297; 1298; 1300; 1308; 1310; 1311; 1312; 1320; 1321; 1322; 1415; 1441; 1444; 1445; 1446; 1449; 1461; 1469; 1520; 1524; 1528; 1566; 1580; 1585; 1588; 1600; 1603; 1604; 1606; 1607; 1608; 1620; 1621; 1622; 1624; 1636; 1638; 1639; 1648; 1649; 1650; 1663; 1664; 1673; 1681; 1787; 1855; 1858; 1879; 1885; 1895; 1896 The standards that may be modified as part of this project are as follows: BAL-002-0; BAL-005-0; BAL-006-1; CIP-001-1; COM-001-1; COM-002-2; EOP-001-0; EOP-002-2; EOP-003-1; EOP-004-1; FAC-002-0; IRO-001-1; IRO-004-1; IRO-005-1; MOD-010-0;		

MOD-011-0; MOD-012-0; MOD-013-1; MOD-014-0; MOD-015-0; MOD-016-1; MOD-017-0; MOD-018-0; MOD-019-0; MOD-020-0; MOD-021-0; MOD-024-1; MOD-025-1; PER-004-1; PRC-001-1; PRC-003-1; PRC-004-1; PRC-012-0; PRC-013-0; PRC-014-0; PRC-022-1; PRC-024-1; TOP-001-1; TOP-002-2; TOP-003-0; TOP-004-2; TOP-005-1; TOP-006-1; TOP-007-0; TOP-008-1; VAR-001-1; VAR-002-1; Modifications to associated Glossary Terms.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	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.
☒	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 Authority	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).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	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 reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power 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 power 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 power 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 power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☒	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability 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 Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Windows Open
July 2–13, 2010

Project 2010-12: Order 693 Directives

Initial ballot windows for the proposed standards from the Order 693 Directives are now open **until 8 p.m. Eastern on July 13, 2010**.

Instructions

Members of the ballot pool associated with this project will receive a separate e-mail with a link to the set of ballots and specific instructions for using the new balloting approach. Changes related to each paragraph from Order 693 are being balloted separately and the ballots are significantly different in appearance compared to previous ballots.

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

On March 18, 2010, FERC issued several orders and notices of proposed rulemakings pertaining to standards development activities and processes, suggesting a lack of progress in responding to directives from Order 693 as well in the timeliness of standards development in general. At the May 2010 NERC Board meeting, Gerry Cauley, NERC's President, also expressed these concerns, indicating that the resolution to these concerns is one of NERC's top priorities in the near term. As a result, the Standards Committee has authorized deviations from the normal standards development process for this Order 693 Directives project, as well as other projects that have been through significant stakeholder review through the development process, to demonstrate that the NERC enterprise is responsive to FERC directives.

In Order No. 693, FERC issued many directives to modify NERC Reliability Standards.

Several of the directives appear to be less controversial than others. In an effort to be more responsive, the Standards Committee has approved having NERC assemble a team of experts to assist in reviewing the directives and identifying those which had a significant chance of being non-controversial; i.e., could be modified, balloted, and filed in a very short amount of time.

NERC and its team of experts have identified 34 directives related to 13 standards that seem to be relatively noncontroversial. Working with input from various parts of the industry, a set of proposed changes to meet the directives has been developed. In order to expedite this project, the Standards Committee has approved an accelerated schedule.

The Standards Committee approved the following deviations from the standards development process:

- Post the SAR and proposed revisions for a formal shortened comment period (June 18–July 13, 2010)
- Form the ballot pool during the first 15 days of the comment period (June 18–July 2, 2010)
- Conduct an initial 10-day ballot on a line-item basis (July 2–13, 2010)
- Require the withdrawal from balloting any item that has significant disagreement from stakeholders as evidenced in comments and ballot results
- Allow modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard (recirculation ballot July 20–30, 2010)

The directives have been summarized in the tables in the balloting form. Each table addresses a set of directives associated with a standard. Following each table is a set of questions seeking feedback on the proposed modifications. In order to be responsive to these directives, please consider the following when voting on these standards:

- Does the change harm reliability?
- Does the change improve reliability?
- Does the change neither harm nor improve reliability, but make the standard (or the Commission's expectations regarding the standard) clearer?
- Are there modifications you can propose that would make the changes more acceptable and still be responsive to the Commission's directives?

It is the goal of this project to focus on items that appear to be widely supported. If you can identify changes that will assist in the acceptance of these changes, please feel free to suggest them.

Project page: http://www.nerc.com/filez/standards/Project2010-12_Order-693_Directives.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

Unofficial Comment Form for Project 2010-12 — Order 693 Directives

Please **DO NOT** use this form. Please use the electronic form at the link below to submit comments on the current drafts of BAL-002-1, BAL-005-1, EOP-001-2, EOP-002-3, EOP-003-2, EOP-004-2, FAC-002-1, MOD-017-1, MOD-019-1, MOD-020-1, MOD-021-2, PRC-004-2, and VAR-001-2. Comments must be submitted by **July 13, 2010.** If you have questions please contact **Andy Rodriquez** at Andy.Rodriquez@nerc.net or by telephone at 609-452-8060.

Background Information

In Order No. 693, the Commission issued many directives to modify the Reliability Standards. The Commission has expressed concern that the industry and NERC have been less responsive than desired in providing a timely resolution to those directives.

Several of the directives appear to be less controversial than others. In an effort to be more responsive, the Standards Committee has approved having NERC assemble a team of experts to assist in reviewing the directives and identifying those which had a significant change of being non-controversial; i.e., could be modified, balloted, and filed in a very short amount of time.

NERC and its team of experts have identified 37 directives related to 14 standards that seem to be relatively non-controversial. Working with input from various parts of the industry, a set of proposed changes to meet the directives has been developed. In order to expedite this project, the Standards Committee has approved an accelerated schedule:

- Post the SAR and proposed revisions for a formal 25-day comment period (June 18-July 13, 2010)
- Form the ballot pool during the first 15 days of the comment period (June 18 – July 2, 2010)
- Conduct an initial 10-day ballot on a line item basis (July 3-13, 2010)
- Require the withdrawal from balloting any item that has significant disagreement from stakeholders as evidenced in comments and ballot results
- Allow modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard. (Recirculation ballot July 20-30, 2010)

This posting represents the first formal review of the SAR related to this effort as well as the proposed changes. The directives have been summarized in the tables on the following pages. Each table addresses a set of directives associated with a standard. Following each table is a set of questions seeking feedback on the proposed modifications. In order to be responsive to these directives, please consider the following when commenting on these standards:

- Does the change harm reliability?
- Does the change improve reliability?
- Does the change neither harm nor improve reliability, but make the standard (or the Commission's expectations regarding the standard) clearer?
- Are there modifications you can propose that would make the changes more acceptable and still be responsive to the Commission's directives?

NERC is seeking comments on these draft standards. It is the goal of this project to focus on items that appear to be widely supported. If you can identify changes that will assist in the acceptance of these changes, please feel free to suggest them.

Several changes were made to the BAL-002 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
321	The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary.	BAL-002-1	Modified Section B Requirement R4.2 and R6.2.
321	As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.	BAL-002-1	Modified Section D 1 and 1.1
330	We direct the ERO to submit a modification to BAL-002-0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.	BAL-002-1	Modified Section B Requirement R1. Modified definitions of "Operating Reserve - Spinning," and "Operating Reserve – Supplemental." Deleted definition of "Spinning Reserve."
335	Accordingly, the Commission directs the ERO to explicitly allow DSM as a resource for contingency reserves, and clarifies that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.	BAL-002-1	Modified definition of "Demand Side Management."
1232	We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.	BAL-002-1	Modified definition of "Demand Side Management."

Do you believe the changes made in response to the directive(s) contained in Paragraph 321, 330, 335 and 1232 of Order No. 693 are both valid and address the directive(s)?

1. **Changes for directives in Paragraph 321** ☐ **Yes** ☐ **No**
2. **Changes for directives in Paragraph 330** ☐ **Yes** ☐ **No**
3. **Changes for directives in Paragraph 335** ☐ **Yes** ☐ **No**
4. **Changes for directives in Paragraph 1232** ☐ **Yes** ☐ **No**

If you answered no to any of the above, please offer any comments or suggestions you may have.

Comments:

Several changes were made to the BAL-005 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
404	The Commission clarifies that its direction to the ERO in this section is for it to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct control load management as regulating reserves, subject to the clarifications provided in this section.	BAL-005-1	Modified title of standards to be “Automatic Resource Control.” Modified definition of “Automatic Generation Control.” Added definition of “Automatic Resource Control.” Modified definition of “Regulating Reserve.” Modified Purpose (Section A 3) of standard. Modified Section B Requirements R2, R6, R7, and R15. Modified VSLs for R2, R7, and R15.
415	Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission’s proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO’s Work Plan. 410. Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area. 411. FirstEnergy states that Requirement R17 should include only “control center devices” instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term “check” in Requirement R17 needs to be clarified.	BAL-005-1	Modified Section B Requirement R17. Modified VSLs for R17. Deleted interpretations, as they have been incorporated into R17.
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management	BAL-005-1	Modified title of standards to be “Automatic Resource Control.” Modified definition of “Automatic Generation Control.” Added definition of “Automatic Resource Control.” Modified definition of “Regulating Reserve.” Modified Purpose (Section A 3) of standard. Modified Section B Requirements R2, R6, R7, and R15.

Paragraph	Directive Language	Standard No.	NERC Comments
			Modified VSLs for R2, R7, and R15.
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using nonfarm service	BAL-005-1	Modified Section B Requirement R5.

Do you believe the changes made in response to the directive(s) contained in Paragraph 404, 415, and 420 of Order No. 693 are both valid and address the directive(s)?

5. **Changes for directives in Paragraph 404** ☐ Yes ☐ No
6. **Changes for directives in Paragraph 415** ☐ Yes ☐ No
7. **Changes for directives in Paragraph 420** ☐ Yes ☐ No

If you answered no to any of the above, please offer any comments or suggestions you may have.
Comments:

Several changes were made to the EOP-001 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
565	The Commission agrees with ISO-NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the “for consideration” elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.	EOP-001-2	Modified Section B Requirement R4. Modified VSLs for R4.
571	As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that “insufficient transmission capability” could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.	EOP-001-2	Modified EOP-001 instead of EOP-002. Modified Section B Requirement R2.1.

Do you believe the changes made in response to the directive(s) contained in Paragraph 565 and 571 of Order No. 693 are both valid and address the directive(s)?

8. **Changes for directives in Paragraph 565** ☐ **Yes** ☐ **No**
9. **Changes for directives in Paragraph 571** ☐ **Yes** ☐ **No**

If you answered no to any of the above, please offer any comments or suggestions you may have.
Comments:

Several changes were made to the EOP-002 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
577	A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.	EOP-002-3 (No changes to standard)	This directive has already been addressed in IRO-006-4.
582	Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. 579. ISO-NE states that Requirement R2 essentially requires the same actions covered by ISO-NE Operating Procedure No. 4. ISO-NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO-NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO-NE procedures. ISO-NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.	EOP-002-3	Modified Section B Requirement R2.
582	Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.	EOP-002-3	Added Measures for R4, R5, R6, and R7.
573	Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.	EOP-002-3	Modified Section B Requirement R6. Modified VSLs for R6.

Do you agree that the directive in Paragraph 577 has already been addressed as noted above and do you believe the changes made in response to the directive(s) contained in Paragraph 582, and 573 of Order No. 693 are both valid and address the directive(s)?

10. Paragraph 577 already addressed ☐ Yes ☐ No

11. Changes for directives in Paragraph 582 ☐ Yes ☐ No

12. Changes for directives in Paragraph 573 ☐ Yes ☐ No

If you answered no to any of the above, please offer any comments or suggestions you may have.
Comments:

Several changes were made to the EOP-003 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
601	We also note that APPA raise(s) issues regarding coordination of trip settings and automatic and manual load shedding plans. The Commission directs the ERO to consider these comments in future modification to the Reliability Standard through the Reliability Standards development process. 598 In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners.	EOP-003-2	Modified Section B Requirement R3.
603	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-003-1 through the Reliability Standards development process that requires periodic drills of simulated load shedding.	EOP-003-2	Added Section B Requirements R9 and R10. Added VSLs for R9 and R10.

Do you believe the changes made in response to the directive(s) contained in Paragraph 601 and 603 of Order No. 693 are both valid and address the directive(s)?

13. Changes for directives in Paragraph 601 ☐ Yes ☐ No

14. Changes for directives in Paragraph 603 ☐ Yes ☐ No

If you answered no to any of the above, please offer any comments or suggestions you may have.
Comments:

Several changes were made to the EOP-004 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
612	APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.	EOP-004-2	Modified Section B Requirement R2 and added Requirement R3. Added VSL for R3.
615	The Commission declines to address Xcel's concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process. 608. Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations. Further, Xcel states that the requirement in Requirement R3.4 for a final report within 60 days may not be feasible given the current WECC process, which among other things, requires the creation of a group to prepare the report and a 30-day posting of a draft report before it becomes final. Xcel also states that if the ultimate purpose of the report is to provide information to avoid a recurrence of a system disturbance, then the Reliability Standard should be revised to require the distribution of the report to similarly situated entities.	EOP-004-2	Addressed definition of "Reportable Event" by adding reference to Attachment 1 in Section B Requirement R4. NERC concurs with FERC that Xcel's concerns regarding the WECC process should be handled through a request for a Variance. With regard to distribution of reports, NERC currently addresses this as the ERO.

Do you believe the changes made in response to the directive(s) contained in Paragraph 612 and 615 of Order No. 693 are both valid and address the directive(s)?

15. Changes for directives in Paragraph 612 ☐ **Yes** ☐ **No**

16. Changes for directives in Paragraph 615 ☐ **Yes** ☐ **No**

If you answered no to any of the above, please offer any comments or suggestions you may have.
Comments:

A change was made to the FAC-002 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	NERC Comments
693	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.	FAC-002-1	Modified Section B Requirement R1.4

Do you believe the changes made in response to the directive(s) contained in Paragraph 693 of Order No. 693 are both valid and address the directive(s)?

17. Changes for directives in Paragraph 693 ☐ **Yes** ☐ **No**

If you answered no to the above, please offer any comments or suggestions you may have.

Comments:

Several changes were made to the MOD-017 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
1249	The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.	MOD-017-1	Modified Section B Requirement R1.1, R1.2. Modified VSLs for R1.
1250	We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.	MOD-017-1	Modified Section B Requirement R1.1, R1.2. Modified VSLs for R1.
1251	The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.	MOD-017-1	Added Section B Requirement R1.5. Modified VSLs for R1.
1252	The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.	MOD-017-1	Added Section B Requirement R2. Added Measure M2 and VSLs for R2.
1255	We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.	MOD-017-1	Added Section A 4.4 (Transmission Planner). Modified Section B Requirement R1 and R2. Modified Measure M1.

Do you believe the changes made in response to the directive(s) contained in Paragraph 1249, 1250, 1251, 1252, and 1255 of Order No. 693 are both valid and address the directive(s)?

18. **Changes for directives in Paragraph 1249** ☐ Yes ☐ No
19. **Changes for directives in Paragraph 1250** ☐ Yes ☐ No
20. **Changes for directives in Paragraph 1251** ☐ Yes ☐ No
21. **Changes for directives in Paragraph 1252** ☐ Yes ☐ No
22. **Changes for directives in Paragraph 1255** ☐ Yes ☐ No

If you answered no to any of the above, please offer any comments or suggestions you may have.

Comments:

Several changes were made to the MOD-019 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
1276	The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission’s concern.	MOD-019-1	Modified Section B Requirement R1.
1277	We direct the ERO to include APPA’s proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.	MOD-019-1	Added Section B Requirement R2. Added VSLs for R2.

Do you believe the changes made in response to the directive(s) contained in Paragraph 1276 and 1277 of Order No. 693 are both valid and address the directive(s)?

23. Changes for directives in Paragraph 1276 ☐ **Yes** ☐ **No**

24. Changes for directives in Paragraph 1277 ☐ **Yes** ☐ **No**

If you answered no to any of the above, please offer any comments or suggestions you may have.

Comments:

Several changes were made to the MOD-020 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	NERC Comments
1287	We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	MOD-020-1	Modified Section B Requirement R1. Added Section B Requirement R2. Added VSLs for R2.

Do you believe the changes made in response to the directive(s) contained in Paragraph 1287 of Order No. 693 are both valid and address the directive(s)?

25. Changes for directives in Paragraph 1287 ☐ **Yes** ☐ **No**

If you answered no to the above, please offer any comments or suggestions you may have.

Comments:

Changes were made to the MOD-021 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	NERC Comments
1300	The Commission directs the ERO to modify the title and purpose statement to remove the word “controllable.” We note that no commenter disagrees.	MOD-021-1	Modified Section A 1 and 3.

Do you believe the changes made in response to the directive(s) contained in Paragraph 1300 of Order No. 693 are both valid and address the directive(s)?

26. Changes for directives in Paragraph 1300 ☐ **Yes** ☐ **No**

If you answered no to the above, please offer any comments or suggestions you may have.

Comments:

Several changes were made to the PRC-004 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
1469	Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.	PRC-004-2	Modified Section B Requirements R1, R2, and R3.
1469	We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.	PRC-004-2	Modified Section B Requirements R1 and R3. Modified Measures M1 and M3. Modified Data Retention.

Do you believe the changes made in response to the directive(s) contained in Paragraph 1469 of Order No. 693 are both valid and address the directive(s)?

27. Changes for directives in Paragraph 1469 ☐ **Yes** ☐ **No**

If you answered no to the above, please offer any comments or suggestions you may have.

Comments:

Several changes were made to the VAR-001 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
1858	The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	VAR-001-2	Added Section A 4.3. Modified Section B Requirement R5.
1879	The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1.	VAR-001-2	Modified Section B Requirements R2, R5, R8, and R9.
1879	While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements. 1878. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.	VAR-001-2 (No changes to standard)	SMA's comments do not seem to require a response. SoCal Edison expresses some concern with dispatch of controllable load having the potential to reduce available generation. However, the standard already includes load shedding in the standard, so there is no more risk than what is currently in the standard. Entities are still expected to evaluate their options and implement the best choice(s) available to them.

Do you believe the changes made in response to the directive(s) contained in Paragraph 1858 and 1879 of Order No. 693 are both valid and address the directive(s)?

28. Changes for directives in Paragraph 1858 ☐ **Yes** ☐ **No**

29. Changes for directives in Paragraph 1879 ☐ **Yes** ☐ **No**

If you answered no to any of the above, please offer any comments or suggestions you may have.
Comments:

30. The motivation for this project is to demonstrate that NERC is working to address the directives in Order 693. Do you agree with this?

☐ **Yes**

☐ **No**

Comments:

31. **Are you aware of any conflicts between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?**

    ☐ **Yes**

    ☐ **No**

    Comments:

32. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on** the proposed SAR or standards**.**

    Comments:

Several changes were made to the BAL-002 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
321	The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary.	BAL-002-1	Modified Section B Requirement R4.2 and R6.2.
321	As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.	BAL-002-1	Modified Section D 1 and 1.1
330	We direct the ERO to submit a modification to BAL-002-0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.	BAL-002-1	Modified Section B Requirement R1. Modified definitions of "Operating Reserve - Spinning," and "Operating Reserve – Supplemental." Deleted definition of "Spinning Reserve."
335	Accordingly, the Commission directs the ERO to explicitly allow DSM as a resource for contingency reserves, and clarifies that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.	BAL-002-1	Modified definition of "Demand Side Management."
1232	We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.	BAL-002-1	Modified definition of "Demand Side Management."

Please indicate your vote for the following changes:

1. **Changes for directives in Paragraph 321** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**
   Comments:
2. **Changes for directives in Paragraph 330** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**
   Comments:
3. **Changes for directives in Paragraph 335** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**
   Comments:
4. **Changes for directives in Paragraph 1232** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**
   Comments:

Several changes were made to the BAL-005 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
404	The Commission clarifies that its direction to the ERO in this section is for it to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct control load management as regulating reserves, subject to the clarifications provided in this section.	BAL-005-1	Modified title of standards to be "Automatic Resource Control." Modified definition of "Automatic Generation Control." Added definition of "Automatic Resource Control." Modified definition of "Regulating Reserve." Modified Purpose (Section A 3) of standard. Modified Section B Requirements R2, R6, R7, and R15. Modified VSLs for R2, R7, and R15.
415	Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission's proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO's Work Plan. 410. Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area. 411. FirstEnergy states that Requirement R17 should include only "control center devices" instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term "check" in Requirement R17 needs to be clarified.	BAL-005-1	Modified Section B Requirement R17. Modified VSLs for R17. Deleted interpretations, as they have been incorporated into R17.
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management	BAL-005-1	Modified title of standards to be "Automatic Resource Control." Modified definition of "Automatic Generation Control." Added definition of "Automatic Resource Control." Modified definition of "Regulating Reserve." Modified Purpose (Section A 3) of standard. Modified Section B Requirements R2, R6, R7, and R15. Modified VSLs for R2, R7, and R15.

Paragraph	Directive Language	Standard No.	NERC Comments
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using nonfarm service	BAL-005-1	Modified Section B Requirement R5.

Please indicate your vote for the following changes:

5. **Changes for directives in Paragraph 404** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**
   Comments:
6. **Please provide your opinion regarding the Paragraph 404 VSL changes** ☐ **In Favor** ☐ **Opposed**
7. **Changes for directives in Paragraph 415** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**
   Comments:
8. **Please provide your opinion regarding the Paragraph 415 VSL changes** ☐ **In Favor** ☐ **Opposed**
9. **Changes for directives in Paragraph 420** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**
   Comments:
10. **Please provide your opinion regarding the Paragraph 420 VSL changes** ☐ **In Favor** ☐ **Opposed**

Several changes were made to the EOP-001 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
565	The Commission agrees with ISO-NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the “for consideration” elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.	EOP-001-2	Modified Section B Requirement R4. Modified VSLs for R4.
571	As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that “insufficient transmission capability” could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.	EOP-001-2	Modified EOP-001 instead of EOP-002. Modified Section B Requirement R2.1.

Please indicate your vote for the following changes:

11. **Changes for directives in Paragraph 565** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

12. **Please provide your opinion regarding the Paragraph 565 VSL changes** ☐ **In Favor** ☐ **Opposed**

13. **Changes for directives in Paragraph 571** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

Several changes were made to the EOP-002 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
577	A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.	EOP-002-3 (No changes to standard)	This directive has already been addressed in IRO-006-4.
582	Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. 579. ISO-NE states that Requirement R2 essentially requires the same actions covered by ISO-NE Operating Procedure No. 4. ISO-NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO-NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO-NE procedures. ISO-NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.	EOP-002-3	Modified Section B Requirement R2.
582	Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.	EOP-002-3	Added Measures for R4, R5, R6, and R7.
573	Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.	EOP-002-3	Modified Section B Requirement R6. Modified VSLs for R6.

Please indicate your vote for the following changes:

14. **Changes for directives in Paragraph 577** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

15. **Changes for directives in Paragraph 582** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

16. **Changes for directives in Paragraph 573** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

17. Please provide your opinion regarding the Paragraph 573 VSL changes ☐ In Favor ☐ Opposed

Several changes were made to the EOP-003 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
601	We also note that APPA raise(s) issues regarding coordination of trip settings and automatic and manual load shedding plans. The Commission directs the ERO to consider these comments in future modification to the Reliability Standard through the Reliability Standards development process. 598 In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners.	EOP-003-2	Modified Section B Requirement R3.
603	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-003-1 through the Reliability Standards development process that requires periodic drills of simulated load shedding.	EOP-003-2	Added Section B Requirements R9 and R10. Added VSLs for R9 and R10.

Please indicate your vote for the following changes:

18. **Changes for directives in Paragraph 601** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

19. **Changes for directives in Paragraph 603** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

20. **Please provide your opinion regarding the Paragraph 420 VRFs and VSLs** ☐ **In Favor** ☐ **Opposed**

Several changes were made to the EOP-004 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
612	APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.	EOP-004-2	Modified Section B Requirement R2 and added Requirement R3. Added VSL for R3.
615	The Commission declines to address Xcel's concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process. 608. Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations. Further, Xcel states that the requirement in Requirement R3.4 for a final report within 60 days may not be feasible given the current WECC process, which among other things, requires the creation of a group to prepare the report and a 30-day posting of a draft report before it becomes final. Xcel also states that if the ultimate purpose of the report is to provide information to avoid a recurrence of a system disturbance, then the Reliability Standard should be revised to require the distribution of the report to similarly situated entities.	EOP-004-2	Addressed definition of "Reportable Event" by adding reference to Attachment 1 in Section B Requirement R4. NERC concurs with FERC that Xcel's concerns regarding the WECC process should be handled through a request for a Variance. With regard to distribution of reports, NERC currently addresses this as the ERO.

Please indicate your vote for the following changes:

21. **Changes for directives in Paragraph 612** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

22. **Please provide your opinion regarding the Paragraph 612 VRF and VSLs** ☐ **In Favor** ☐ **Opposed**

23. **Changes for directives in Paragraph 615** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

A change was made to the FAC-002 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	NERC Comments
693	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.	FAC-002-1	Modified Section B Requirement R1.4

Please indicate your vote for the following changes:

24. **Changes for directives in Paragraph 693** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

Several changes were made to the MOD-017 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
1249	The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.	MOD-017-1	Modified Section B Requirement R1.1, R1.2. Modified VSLs for R1.
1250	We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.	MOD-017-1	Modified Section B Requirement R1.1, R1.2. Modified VSLs for R1.
1251	The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.	MOD-017-1	Added Section B Requirement R1.5. Modified VSLs for R1.
1252	The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.	MOD-017-1	Added Section B Requirement R2. Added Measure M2 and VSLs for R2.
1255	We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.	MOD-017-1	Added Section A 4.4 (Transmission Planner). Modified Section B Requirement R1 and R2. Modified Measure M1.

Please indicate your vote for the following changes:

25.Changes for directives in Paragraph 1249 ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

26. Please provide your opinion regarding the Paragraph 1249 VSL changes ☐ In Favor ☐ Opposed

27. Changes for directives in Paragraph 1250 ☐ Approve ☐ Disapprove ☐ Abstain

Comments:

28. Please provide your opinion regarding the Paragraph 1250 VSL changes ☐ In Favor ☐ Opposed

29. Changes for directives in Paragraph 1251 ☐ Approve ☐ Disapprove ☐ Abstain

Comments:

30. Please provide your opinion regarding the Paragraph 1251 VSL changes ☐ In Favor ☐ Opposed

31. Changes for directives in Paragraph 1252 ☐ Approve ☐ Disapprove ☐ Abstain

Comments:

32. Please provide your opinion regarding the Paragraph 1252 VRF and VSLs ☐ In Favor ☐ Opposed

33. Changes for directives in Paragraph 1255 ☐ Approve ☐ Disapprove ☐ Abstain

Comments:

Several changes were made to the MOD-019 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
1276	The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	MOD-019-1	Modified Section B Requirement R1.
1277	We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.	MOD-019-1	Added Section B Requirement R2. Added VSLs for R2.

Please indicate your vote for the following changes:

34. Changes for directives in Paragraph 1276 ☐ Approve ☐ Disapprove ☐ Abstain

Comments:

35. Changes for directives in Paragraph 1277 ☐ Approve ☐ Disapprove ☐ Abstain

Comments:

36. Please provide your opinion regarding the Paragraph 1277 VRF and VSLs ☐ In Favor ☐ Opposed

Several changes were made to the MOD-020 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	NERC Comments
1287	We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	MOD-020-1	Modified Section B Requirement R1. Added Section B Requirement R2. Added VSLs for R2.

Please indicate your vote for the following changes:

37. **Changes for directives in Paragraph 1287** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

38. **Please provide your opinion regarding the Paragraph 1287 VRF and VSLs** ☐ **In Favor** ☐ **Opposed**

Changes were made to the MOD-021 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	NERC Comments
1300	The Commission directs the ERO to modify the title and purpose statement to remove the word “controllable.” We note that no commenter disagrees.	MOD-021-1	Modified Section A 1 and 3.

Please indicate your vote for the following changes:

39. **Changes for directives in Paragraph 1300** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

Several changes were made to the PRC-004 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
1469	Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.	PRC-004-2	Modified Section B Requirements R1, R2, and R3.
1469	We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.	PRC-004-2	Modified Section B Requirements R1 and R3. Modified Measures M1 and M3. Modified Data Retention.

Please indicate your vote for the following changes:

40. Changes for directives in Paragraph 1469 ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

Several changes were made to the VAR-001 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	NERC Comments
1858	The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	VAR-001-2	Added Section A 4.3. Modified Section B Requirement R5.
1879	The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1.	VAR-001-2	Modified Section B Requirements R2, R5, R8, and R9.
1879	While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements. 1878. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.	VAR-001-2 (No changes to standard)	SMA's comments do not seem to require a response. SoCal Edison expresses some concern with dispatch of controllable load having the potential to reduce available generation. However, the standard already includes load shedding in the standard, so there is no more risk than what is currently in the standard. Entities are still expected to evaluate their options and implement the best choice(s) available to them.

Please indicate your vote for the following changes:

41. **Changes for directives in Paragraph 1858** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

42. **Changes for directives in Paragraph 1879** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Project 2010-12 — Order 693 Directives

The Order 693 Directives Drafting Team thanks all commenters who submitted comments on the current drafts of BAL-002-1, BAL-005-1, EOP-001-2, EOP-002-3, EOP-003-2, EOP-004-2, FAC-002-1, MOD-017-1, MOD-019-1, MOD-020-1, MOD-021-2, PRC-004-2, and VAR-001-2. These standards were posted for a 15-day public comment period from June 18, 2010 through July 2, 2010. The 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 45 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The work for this project has been posted on the following site:

http://www.nerc.com/filez/standards/Project2010-12_Order-693_Directives.html

Stakeholder comments were used to determine whether each proposed modification should move forward to a second ballot and to determine, if the modification was supported by stakeholders, whether additional modifications would improve the proposed language. The following table summarizes the disposition of the proposed modifications.

Standard	Directive Reference	Did Comments Indicate the Modification Should Move Forward?	If Yes, Were Changes Made?
BAL-002-1	P330 P335 P1232	No – the proposed modifications were removed from the standard	
	P321	Yes	Modified R4.2 and R6.2
BAL-005-1	P404 P415 P420	No – the proposed modifications were removed from the standard	
EOP-001-2	P571	No – the proposed modifications were removed from the standard	
EOP-002-3	P573	No – the proposed modifications were removed from the standard	
	P577	No – no modifications were proposed; stakeholders agreed the directive was addressed in IRO-006-4	
	P582	Yes	Modified M5
EOP-003-2	P601 P603	No – the proposed modifications were removed from the standard	
EOP-004-2	P612 P615	No – the proposed modifications were removed from the standard	
FAC-002-1	P693	Yes	No modifications
MOD-017-1	P1249 P1250 P1251 P1252 P1255	No – the proposed modifications were removed from the standard	
MOD-019-1	P1276	No – the proposed modifications were removed	

Standard	Directive Reference	Did Comments Indicate the Modification Should Move Forward?	If Yes, Were Changes Made?
	P1277	from the standard	
MOD-020-1	P1287	No – the proposed modifications were removed from the standard	
MOD-021-1	P1300	Yes	No modifications
PRC-004-2	P1469	Partial – changes to expand applicability to include LSEs and TOPs were removed; Changes to replace the RRO with RE were retained	Modified M1, M2, M3
VAR-001-2	P1858 P1879	Yes	Modified R2, R5, R9

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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@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.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Councilq	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	Chantel Haswell	FPL Group, Inc.	NPCC	5
14.	David Kiguel	Hydro One Networks Inc.	NPCC	1
15.	Michael R. Lombardi	Northeast Utilities	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16. Randy MacDonald	New Brunswick System Operator	NPCC	2										
17. Bruce Metruck	New York Power Authority	NPCC	6										
18. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10										
19. Robert Pellegrini	The United Illuminating Company	NPCC	1										
20. Michael Schiavone	National Grid	NPCC	1										
2.	Group	Jim Case	SERC OC Standards Review Group	x		x							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gerald Beckerle	Ameren	SERC	1, 3
2.	Alvis Lanton	Southern Illinois Power Cooperative	SERC	1, 3, 5
3.	Rene' Free	SCPSA	SERC	1, 3, 5, 9
4.	Vicky Budreau	SCPSA	SERC	1, 3, 5, 9
5.	Glenn Stephens	SCPSA	SERC	1, 3, 5, 9
6.	Wayne Mitchell	Entergy	SERC	1, 3
7.	Melinda Montgomery	Entergy	SERC	1, 3
8.	Jennifer Weber	TVA	SERC	1, 3, 5, 9
9.	Larry Akens	TVA	SERC	1, 3, 5, 9
10.	Rick Myers	EEI	SERC	1, 5
11.	Andy Burch	EEI	SERC	1, 5
12.	Gary Hutson	SMEPA	SERC	1, 3, 5
13.	Eugene Warnecke	Ameren	SERC	1, 3
14.	Paul Turner	GASOC	SERC	1, 3, 5
15.	Louis Slade	Dominion VP	SERC	1, 3
16.	Robert Thomasson	BREC	SERC	1, 3, 5, 9
17.	Timmy LeJeune	La Generating	SERC	1, 3, 5
18.	Derek Rahn	E.ON.US	SERC	1, 3, 5
19.	Richard Chapman	OMU	SERC	1, 3, 5
20.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9
21.	Randy Castello	Mississippi Power	SERC	1, 3, 5
22.	John Troha	SERC	SERC	10

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	NERC Standards Review Subcommittee										x

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
10.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
11.	Scott Nickels	Rochester Public Utilties	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	6, 1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Andy Tillery	Southern Company Transmission	x		x							

	Additional Member	Additional Organization	Region	Segment Selection
1.	JT Wood		SERC	1
2.	SERC OC	SERC	SERC	
3.	Marc Butts		SERC	1
4.	Bill Schultz		SERC	3
5.	Steve Carter		SERC	3
6.	Chris Wilson		SERC	1
7.	Phil Winston		SERC	3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	x		x		x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Godfrey	Delmarva Power & Light	RFC	1
2.	Rob Reuter	Potomac Electric Power Co.	RFC	3
3.	Michael mayer	Delmarva Power & Light	RFC	3

	Additional Member	Additional Organization	Region	Segment Selection
4.	Jim Petrella	Atlantic City Electric	RFC	3
5.	Kara Dundas	Conectiv Energy Supply, Inc	RFC	5
6.	James Newton	Pepco Energy Services	RFC	6

		Commenter	Organization	Industry Segment									
				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.	Jim Cyrulewski	JDRJC Associates, LLC	RFC	8
2.	Barb Kedrowski	We Energies	RFC	3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Louis Slade	Dominion	x		x		x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea		SERC	3
2.	Mike Garton		NPCC	5
3.	John Loftis		SERC	1
4.	Louis Slade		RFC	6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Frank Gaffney	Florida Municipal Power Agency	x		x		x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	Utilities Commission of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	1
3.	James Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utilities Authority	FRCC	4

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tom Abrams		SERC	1, 9
2.	Glenn Stephens		SERC	1, 9
3.	Rene' Free		SERC	1, 9
4.	Vicky Budreau		SERC	1, 9
5.	Jim Peterson		SERC	1, 9

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

	Additional Member	Additional Organization	Region	Segment Selection
6.	Wayne Ahl		SERC	1, 9

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Bob Canada and Brian Evans-Mongeon	Disturbance and Sabotage Reporting Drafting Team	x	x	x		x					

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Hartman	ERCOT	ERCOT	2
2.	Bob Canada	SCS	SERC	1, 3, 5
3.	Michele Draxton	Constellation Energy	RFC	5
4.	Chris Boucher	BC Hydro	WECC	1
5.	Tom Moleski	PJM	RFC	2
6.	Joe Depoorter	Madison Gas & Electric	MRO	1
7.	Brian Evans-Mongeon	Utility Services	NA - Not Applicable	NA
8.	Brian Harrell	SERC	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Ben Li	IRC Standards Review Committee		x								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	SPP	SPP	2
2.	Bill Phillips	MISO	MRO	2
3.	Steve Myers	ERCOT	ERCOT	2
4.	James Castle	NYISO	NPCC	2
5.	Patrick Brown	PJM	RFC	2
6.	Mark Thompson	AESO	WECC	2
7.	Matt Goldberg	ISO-NE	NPCC	2
8.	Greg Van Pelt	CAISO	WECC	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Gammon	Kansas City Power & Light	x		x		x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jennifer Flandermeyer	KCPL	SPP	1, 3, 5, 6
2.	Jim Useldinger	KCPL	SPP	1, 3, 5, 6
3.	Harold Wyble	KCPL	SPP	1, 3, 5, 6
4.	Denney Fales	KCPL	SPP	1, 3, 5, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Rod Lewis	KCPL	SPP 1, 3, 5, 6										
6.	Tom Saitta	KCPL	SPP 1, 3, 5, 6										
7.	Tim Hinken	KCPL	SPP 1, 3, 5, 6										
13.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	x		x		x	x				
14.	Individual	Steve Rueckert	Western Electricity Coordinating Council										x
15.	Individual	Brent ingebrigtson	E.ON U.S.	x		x		x	x				
16.	Individual	Sandra Shaffer	PacifiCorp	x		x		x	x				
17.	Individual	Dan Roethemeyer	Dynegy Inc.					x					
18.	Individual	Steve Alexanderson	Central Lincoln			x	x						
19.	Individual	Terry Vogel	central Maine Power Company	x									
20.	Individual	Scott Barfield-McGinnis	Georgia System Operations Corporation			x	x						
21.	Individual	Jonathan Appelbaum	United Illuminating Company	x									
22.	Individual	Jeff Nelson	Springfield Utility Board			x							
23.	Individual	Bob Thomas	Illinois Municipal Electric Agency				x						
24.	Individual	Ed Davis	Entergy Services	x		x		x	x				
25.	Individual	Michael Ibold	Xcel Energy			x							
26.	Individual	Joylyn Faust	Consumers Energy Company			x	x	x					
27.	Individual	Kirit Shah	Ameren	x		x		x	x				
28.	Individual	Dan Rochester	IESO		x								
29.	Individual	CJ Ingersoll	CECD	N/A									
30.	Individual	Thad Ness	American Electric Power	x		x		x	x				
31.	Individual	David	SDG&E	x									
32.	Individual	Scott Berry	Indiana Municipal Power Agency				x						

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Laura Zotter	ERCOT ISO		x								
34.	Individual	Martin Bauer	US Bureau of Reclamation					x					
35.	Individual	Saurabh Saksena	National Grid	x		x							
36.	Individual	Terri Pyle	Oklahoma Municipal Power Authority				x						

1. **Do you believe the changes made in response to the directive(s) contained in Paragraph 321 of Order No. 693 are both valid and address the directive(s)?**

321	The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary.	BAL-002-1	Modified Section B Requirement R4.2 and R6.2.
321	As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.	BAL-002-1	Modified Section D 1 and 1.1

Organization	Question 1
CECD	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Indiana Municipal Power Agency	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Municipal Power Authority	No
Santee Cooper	No
SERC OC Standards Review Group	No

Organization	Question 1
US Bureau of Reclamation	No
Ameren	Yes
American Electric Power	Yes
Arizona Public Service Company	Yes
Dominion	Yes
Entergy Services	Yes
Georgia System Operations Corporation	Yes
IESO	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Southern Company Transmission	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Xcel Energy	Yes

2. Do you believe the changes made in response to the directive(s) contained in Paragraph 330 of Order No. 693 are both valid and address the directive(s)?

330	We direct the ERO to submit a modification to BAL-002-0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.	BAL-002-1	Modified Section B Requirement R1. Modified definitions of “Operating Reserve - Spinning,” and “Operating Reserve – Supplemental.” Deleted definition of “Spinning Reserve.”

Organization	Question 2
Ameren	No
Arizona Public Service Company	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Muncipal Power Authority	No
Pepco Holdings, Inc. - Affiliates	No

Organization	Question 2
Santee Cooper	No
Southern Company Transmission	No
Xcel Energy	No
American Electric Power	Yes
CECD	Yes
Dominion	Yes
Entergy Services	Yes
IESO	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
SERC OC Standards Review Group	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes
US Bureau of Reclamation	Yes
Western Electricity Coordinating Council	Yes

3. Do you believe the changes made in response to the directive(s) contained in Paragraph 335 of Order No. 693 are both valid and address the directive(s)?

335	Accordingly, the Commission directs the ERO to explicitly allow DSM as a resource for contingency reserves, and clarifies that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.	BAL-002-1	Modified definition of "Demand Side Management."

Organization	Question 3
Ameren	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Muncipal Power Authority	No
Santee Cooper	No

Organization	Question 3
SERC OC Standards Review Group	No
Southern Company Transmission	No
Springfield Utility Board	No
Xcel Energy	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
United Illuminating Company	Yes
US Bureau of Reclamation	Yes
Western Electricity Coordinating Council	Yes

4. Do you believe the changes made in response to the directive(s) contained in Paragraph 1232 of Order No. 693 are both valid and address the directive(s)?

1232	We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.	BAL-002-1	Modified definition of "Demand Side Management."

Organization	Yes or No
Xcel Energy	No
Kansas City Power & Light	No
E.ON U.S.	No
Springfield Utility Board	No
Entergy Services	No
SERC OC Standards Review Group	No
Santee Cooper	No
Southern Company Transmission	No
Ameren	No
Northeast Power Coordinating Council	No
ERCOT ISO	No

Organization	Yes or No
IESO	No
Georgia System Operations Corporation	No
Midwest ISO Standards Collaborators	No
American Electric Power	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Consumers Energy Company	Yes
Florida Municipal Power Agency	Yes
Arizona Public Service Company	Yes
Oklahoma Municipal Power Authority	Yes
Indiana Municipal Power Agency	Yes
CECD	Yes
US Bureau of Reclamation	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Dominion	Yes

Comments on the BAL-002 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received on these modifications and determined that addressing the directives in paragraphs 330, 335, and 1232 will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Specific to the proposed changes to address Paragraph 321, some commenters disagreed with the replacement of Regional Reliability Organization with Regional Entity in Section D1 and D1.1 on the basis that Regional Entity is not defined in the Functional Model. Version 5 Reliability Functional Model Technical Document, Ch. 15, indicates that: "NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC." The Response Team therefore does not find using the term Reliability Entity inappropriate.

Several commenters suggested that instead of replacing "NERC Operating Committee" with "ERO," the standard could be improved in an alternate fashion simply by removing the provisions for unilateral adjustment of these time periods by any group or entity. The Response Team agreed and removed the last two sentences of R4.2 and R6.2, which now read as follows:

R4.2 The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

R6.2 The default Contingency Reserve Restoration Period is 90 minutes.

Organization	Question 4 Comment
IRC Standards Review Committee	Taken in isolation the concept of changing NERC OC to ERO would be reasonable. Taken in conjunction with the entire standard the change becomes a de facto acceptance of the two requirements. Two requirements that require significant review and change. The SAR requestor misses a key point in R4.2 and R6.2 and that is the fact that the requirement itself is about making changes to the DCS recovery period itself. Who makes the change is secondary to the fact that the changes are being allowed at any time without any clarity about implementation and compliance. In a pre-mandatory environment, such changes could be made as needed. However, both R4.2 and R6.2 now need to be reconsidered regarding the implication of "approving" a simplistic change to what may be an inappropriate standard. The Industry must identify such details as whether or not changes are made "annually" or "as needed". What does it mean to "better suit the needs of an Interconnection"? Compliance entities need guidance about how to decide compliance. Do changes resulting from the ERO analysis occur on day-one that the change is made, or is there an implementation grace period - all this needs to be formally explained in the standard. Technically, the two BAL-002 requirements 4.2 and 6.2 that are in effect today, as well as the revised proposed actually introduce the potential to violate the Commission approved NERC standards development process as it allows the standard to be modified by a single entity outside the process. An alternative solution (one that meets the Commission mandate that allows the ERO to offer and equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be

Organization	Question 4 Comment
	modified outside the standards development process. Paragraph 321Taken in isolation the concept of changing Regional Reliability Organization to Regional Entity would be reasonable. But does such a trivial change warrant expedited (i.e. Urgent Action) treatment by bypassing the FERC-approved Reliability Standards Development Process? Paragraph 330Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to provide contingency reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the requirement itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. We do not agree with the proposed definition for DSM and, as a general matter, oppose inclusion or exclusion of specific types of resource or technology that may or may not be used to fulfill a requirement. We believe this results in a “HOW” to meet a requirement instead of “WHAT” to meet the requirements and, have, in the past opposed such specifications within the Standards.The ISO/RTOs currently allow DSM to compete with generation as a resource to supply contingency reserves. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. While these proposed changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply with the directive. We think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM. Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC standards development process (i.e. NAESB participants). Paragraph 335We disagree with striking the word ‘load’ from BAL-001 R1. Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM. Controllable load resource may be something that is specifically included in DSM in that signing up could represent an activity “undertaken by end-use customers, Load -Serving Entities, or their agents or representatives to influence the amount or timing of electricity they use”. It is not clear though because of the ambiguity of the definition particularly since it is not clear what “Activities undertaken by end-use customers” includes. Paragraph 1232The proposed definition of DSM is inappropriate as it proposes to link the definition to a given purpose (i.e. providing one or more services...).Paragraph 1232 directed the ERO to expand the original DSM definition adding the phrase: “any other entities that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement”. The SAR-proposed definition - in addition to including the Order 693 wording - proposes to limit the scope of DSM within a specific type that is eligible for inclusion in being used as a reserve. While this is the intent of the Paragraph 335 directive, such an intent should be met separately in a requirement, not in the definition. Including such wording in the DSM definition would effectively exclude (as DSM) those demand side management resources that do not wish to be included in, or qualify for, providing services traditionally provided by generation resources such as not having the same response characteristics.Although FERC suggested the wording used in this proposal, the requestor is reminded that FERC has repeated stated that equally effective alternatives are appropriate. The words need to

Organization	Question 4 Comment
	be considered and vetted in light of all DSM initiatives. NERC has several DSM activities now in process. The reason for those activities is specifically because DSM (as an evolving technology) is not a well-defined universally accepted term. NERC definitions should not be written in terms of compliance requirement. Such requirements are defined by the standard itself. And such phrase as “of the resources it is replacing” is inappropriate and incorrect. One could ask if it were better to state “of the resources it is competing with”. And will it always compete with generation, may it not “replace” other DSM products? In short, the proposed definition is not a good definition. Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed. Specific to the comment on changes regarding the Regional Entity, Version 5 Reliability Functional Model Technical Document, Ch. 15 indicates that: “NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC.” We do not find using the term Regional Entity inappropriate. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
Kansas City Power & Light	Directives 330, 335, and 1232:In the definitions for “Operating Reserve - Spinning” and “Operating Reserve - Supplemental” the second bulleted item regarding Demand Side Management Resources should refer directly to “disturbance recovery period” instead of “time necessary to provide service”. In addition, it is not clear that Demand Side Management actions can qualify as spinning as the load response or other actions is not automatically responsive to system changes. As an example, one of the actions could be the use of independent distributed generation resources to offset system load which is typically not synchronized to the grid.
E.ON U.S.	E ON U.S. suggests striking the entire last sentence of R4.2 and R6.2. Changing of the disturbance recovery period and the restoration period and the standard should follow the Standard Development Process.Paragraphs 330 & 335 only address the use of DSM for contingency reserves, not “one or more services” E ON U.S. suggests the following edits: Demand-Side Management (DSM): Activities undertaken by end-use customers, Load-Serving Entitiesor their agents or representatives to change electrical demand, without violating Reliability Standards, in order to provide contingency reserves. In order to provide contingency reserve, DSM resources must maintain electrical response characteristics equivalent to or better than the contingency reserve providing generation resources being replaced. Operating Reserve - Spinning: The portion of Operating Reserve consisting of: o Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or o Demand Side Management Resources or other devices with capability to adequately respond within the time necessary to provide the contingency reserve service; or o Load which is fully removed from the system within the Disturbance Recovery Period and remains removed from the system for the duration of the Disturbance Recovery Period following the contingency event.Operating Reserve –

Organization	Question 4 Comment
	Supplemental: The portion of Operating Reserve consisting of: o Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or o Demand Side Management Resources or other devices with capability to adequately respond within the time necessary to provide the contingency reserve service; or o Load which is fully removable from the system within the Disturbance Recovery Period and remains removed from the system for the duration of the Disturbance Recover Period following the contingency event. Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
Springfield Utility Board	Overall SUB supports the intent behind the change but rather than clarify dispatchable and non-dispatchable DSM, these two distinct DSM activities are attached to a very broad definition Demand Side Management and are left unclear. Plus, use of the universal term permiates many standards and creates unintentional consequences. Understanding that DSM permeates multiple standards, completely deleting the definition of DSM may not be practical. However, what may be practical is to add NEW definitions for "Dispatchable Demand Side Management" and "Non-Dispatchable Demand Side Management". SUB suggests that a better clarification would be to. 1) Keep the existing definition of DSM as is. 2) Add a new definition of Non-Dispatchable Demand Side Management: "Non-Dispatchable Demand Side Management, NDSDM, is DSM that influences the amount of electricity used but does not provide for the ability to control the timing of the use to provide the one or more services traditionally provided by generation resources. NDDSM may influence timing of use, but not to provide transmission support services traditionally provided by the dispatch of generation resources " 3) Add a new definition of Dispatchable Demand Side Management: "Dispatchable Demand Side Management, DSDM, is DSM that influences the amount of electricity used and provides for the ability to control the timing of the use without violating Reliability Standards in order to provide the one or more services traditionally provided by generation resources. In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing." 4) The proposed modification to the definition "Operating Reserves" currently refers to the term "Demand Side Management". "Demand Side Management" would be replaced with "Dispatchable Demand Side Management" 5) The proposed modification to the definition "Operating Reserve - Supplemental" currently refers to the term "Demand Side Management". "Demand Side Management" would be replaced with "Dispatchable Demand Side Management" 6)The proposed change to R1 add DSM "R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to

Organization	Question 4 Comment
	respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, Demand Side Management (DSM), or coordinated adjustments to Interchange Schedules."Again, use of the term DSM in the context of BAL-005-1 is overly broad and new definitions (discussed earlier) should be used to clarify what DSM applies to BAL-005-1. Confusion leads to uncoordinated compliance activities and reduction in reliability.New R1 language: "R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, Dispatchable Demand Side Management (DDSM), or coordinated adjustments to Interchange Schedules." Response: Please see our response in the Summary Consideration.
Entergy Services	Paragraph 1232 - in the definition for DSM, we suggest the word "Load"; be replaced with "DSM Products". In the future, loads many not be the only Demand side Product capable of assuming this role."In order to do so, DSM Products must have the same response characteristics (but not necessarily mechanical or physical implementation) ofthe resources it is replacing." Response: Please see our response in the Summary Consideration.
SERC OC Standards Review Group	Paragraph 321 - "While modifications to BAL-002 may address FERC directives, we do not believe simply replacing the NERC OC with the ERO is appropriate or represents the best solution. BAL-002 R4.2 and R6.2 that are in effect today and as proposed actually represent the potential to violate the Commission approved NERC standards development process as it allows the standard to be modified by a single entity outside the process. A superior alternative solution (which meets the Commission mandate that allows the ERO to offer an equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be modified outside the standards development process. "Paragraph 1232 - in the definition for DSM, we suggest the word "Load; be replaced with "DSM Products". In the future, loads many not be the only Demand side Product capable of assuming this role. Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
Santee Cooper	Paragraph 321 - The last sentence of R4.2 and R6.2 should be deleted from the standard. Any changes to standards should follow the ANSI approved standards process. Paragraphs 330, 335, and 1232 - Any changes to NERC definitions should follow the ANSI approved standards process. Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.
Southern Company Transmission	Paragraph 330 - We do not agree with modifying the definition Operating Reserve - Spinning or Operating Reserve - Supplemental. What is different about DSM in new bullet that the existing "load Fully removable..." bullet does not address. FERC has made clear recently through a March 18 order of their concern regarding declining frequency response in the Eastern Interconnection. Because Operating Reserve - Spinning has an implied obligation to include frequency responsive generation, we believe that the inclusion of DSM as written

Organization	Question 4 Comment
	could further reduce frequency response. While some DSM may be frequency responsive, a significant portion may not be. At the very least, this demonstrates this is not low hanging fruit and should be referred to a drafting team. Additionally, we believe the purpose of the BAL-002 standard is to set contingency reserve obligations and is not an appropriate place to modify these definitions.Not sure why Demand Side Management is added to the list in BAL-002, R1 when "Controllable load resources" already existed. The difference is not clear and if it is based on the revised description of Demand Side Management will be problematic because the new definition will not be universally accepted. We disagree with striking load. Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM. Paragraph 335 - Unclear how proposed words on definition accomplish FERC's desire to have them treated comparable. What does the last sentence mean..."response characteristics". All comments and changes ignore the fact that controllable loads are done so under the tariffs and contracts in place with the load not simply the fact that they are loads Paragraph 1232 - In the definition for DSM, we suggest the word "Load" be replaced with "DSM Products". In the future, loads many not be the only Demand side Product capable of assuming this role. Response: Please see our response in the Summary Consideration.
Ameren	Q.2 Comments – (a)In the definition of DSM, the parenthetical addes ambiguity. (b) Likewise, the implication that the DSM does not have to be controlled by an operator, means that DSM will not be comparabale, and will lead to less reliability. (c) In both definitions of Operating Reserve, "control capability" should be followed by "at a dispatch center or control room".Q.3 Comments - The existing definition of Contigency Reserve should be modified to state, "The portion of Operating Reserve used for responding to generation reporatble Disturbance". Q.4 Comments – (a) In R4.2, it should identify who (which group) at ERO; Enforcements, Stanadrds, Event Analysis? (b) What is the appeal process? Response: The Response Team has struck the second sentences of 4.2. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
Northeast Power	The proposed changes from Paragraph 321 should include the striking of the sentence in R4.2 "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating CommitteeERO." It is not enforceable or appropriate

Organization	Question 4 Comment
Coordinating Council	for a FERC approved requirement to be "adjustable" or waived.Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate, and do not agree with the proposed definition for DSM. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. Response: The Response Team has struck the second sentences of 4.2. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
ERCOT ISO	These are not low-hanging fruit because these changes need to be in sync with other efforts underway as indicated in responses to Q2 - Q4 below. Q1 - The changes do not appropriately address the directives. We do not believe you can simply replace the NERC Operating Committee with the ERO in R4.2 and R6.2. We suggest simply deleting the last sentence of R4.2 and the last sentence of R6.2 because if the values of the requirements indeed need to change then the language would need to be revised through the standards development process. Q2 - The NERC Project 2007-05 Balancing Authority Controls is addressing reserves. Q3 and Q4 - There has been a large group working with both NERC (including the Functional Model Working Group) and NAESB on this topic. This is likely to be controversial and not low-hanging fruit.Additionally, ERCOT ISO recommends differentiating between Demand Side Management and Demand Response. NERC, via the Demand Response Data Task Force, provided solid differentiation between the two terms. See page 11 in the final report on the Demand Response Data Availability System (DADS):http://www.nerc.com/docs/pc/drdtf/DADS_Phase_I&II_Final_050510.pdfUnder NERC's definition, DSM includes Energy Efficiency as well as Demand Response. Especially in the context of Contingency Reserves, as proposed here, dispatchable DR should be the only type of resource capable of participating; it is not likely anyone would recommend extending it to Energy Efficiency. Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
IESO	We do not agree with the change of definition of DSM especially the latter part that says: "...in order to provide the one or more services traditionally provided by generation resources. In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing." Further, the term Demand Side Manage Resource is used in the expanded definitions for Operating Reserve - Spinning and Operating Reserve - Supplemental. The word "Resource" should not be capitalized since it would imply a defined term. Paragraph 1232 directs the ERO to expand the definition to add "any other entities that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement". The proposed definition added the above mentioned wording which limit the scope of DSM within a specific type that is eligible for inclusion in the list that can used as a reserve.

Organization	Question 4 Comment
	While this is the intent of the Paragraph 335 directive, such an intent should be met separately in a requirement, not in the definition. Including such wording in the definition exclude those demand that does not wish to be included in, or qualify for, providing services traditionally provided by generation resources such as not having the same response characteristics.We suggest the definition be truncated at "....without violating other Reliability Standard Requirement". The part that says "...in order to provide the one or more.....resources it is replacing." be removed, and whose intent to allow the use of DSM as a resource for contingency reserves, and that it be treated on a comparable basis and must meet similar technical requirements as other resources providing this service be covered by appropriate requirements. Response: Please see our response in the Summary Consideration.
Georgia System Operations Corporation	We do not object to the content or intent of the directive, or to the intent of the proposed changes, however we believe the current wording is confusing. Specifically: 2a) It is not clear who "they" in the first sentence refers to. Grammatically it refers to end-use customers, LSEs, and their agents or representatives, but only end-use customers typically use electricity so we do not believe that was the intent. We suggest changing "the amount or timing of electricity they use" to "the amount or timing of electricity use" 2b) We believe it would read better and be easier to understand if the phrase "without violating Reliability Standards" was changed to "in accordance with Reliability Standards" and moved to after the word "undertaken". 2c) The phrase "in order to provide the one or more services traditionally provided by generation resources" is vague. DSM addresses some of the same objectives as generation when viewed from a very high level, but does so in different ways. We recommend stating the objectives directly by replacing it with "to support voltage or frequency response or the balance of load and generation". If you disagree with this change, change "provide the one or more services" to "provide the services" 2d) We believe the last sentence is unnecessary because the same concept is conveyed in the definitions of spinning and supplemental reserves. If it is retained it should be reworded to improve its clarity. It starts with "In order to do so" but it is not clear exactly what that is referring to. It also says that the loads must have the same response characteristics of the resources it is replacing, but DSM is not defined as loads, but as activities. If it is retained we recommend replacing it with "to fall within the definition of DSM, an activity activities must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves." 2e) Suggested re-wording of DSM: DSM - Programs operated in accordance with Reliability Standards to influence the amount or timing of electricity use in order to balance demand and resources or support frequency response. To fall within the definition of DSM, a program must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves. 2f) We recommend the second bullet of the definition of Spinning and Supplemental Reserves be changed to: Demand Side Management Resources with the capability to adequately respond within the time necessary to provide the service; or

Organization	Question 4 Comment
	2h) We recommend the third bullet of the definition of Spinning and Supplemental Reserves be deleted because anything covered by the third bullet would also be covered by the second. 2i) In BAL 002 R1 the term “controllable load resource” was changed to “controllable resource” We do not understand the intended meaning of controllable resources and it is not a defined term. We believe that a controllable resource would be either a form of generation or DSM which are already listed in R1; therefore we recommend that it be deleted. Response: Please see our response in the Summary Consideration.
Midwest ISO Standards Collaborators	While modifications to BAL-002 may address FERC directives, we do not believe simply replacing the NERC OC with the ERO is appropriate or represents the best solution. BAL-002 R4.2 and R6.2 that are in effect today and as proposed actually represent the potential to violate the Commission approved NERC standards development process as it allows the standard to be modified by a single entity outside the process. A superior alternative solution (which meets the Commission mandate that allows the ERO to offer an equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be modified outside the standards development process. Modifying sub-requirements R4.2 and R6.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified its course of action would be. While we are supportive of allowing DSM to compete with generation as a resource to supply contingency reserves, we do not believe the directives from paragraph 330, 335, and 1232 regarding modifying BAL-002 represents low hanging fruit. While these proposed changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has on many occasions stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply with the directive. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. Unfortunately, we think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM. Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC standards development process (i.e. NAESB participants). We do not agree with modifying the definition Operating Reserve - Spinning or Operating Reserve - Supplemental. FERC has made clear recently through a March 18 order of their concern regarding declining frequency response in the Eastern Interconnection. Because Operating Reserve - Spinning has an implied obligation to include frequency responsive generation, we believe that the inclusion of DSM as written could further reduce frequency response. While some DSM may be frequency responsive, a significant portion may not be. At the very least, this demonstrates this is not low hanging fruit and should be referred to a drafting team.

Organization	Question 4 Comment
	Additionally, we believe the purpose of the BAL-002 standard is to set contingency reserve obligations and is not an appropriate place to modify these definitions.BAL-001 R1 - We disagree with striking load. Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM. Controllable load resource may be something that is specifically included in DSM in that signing up could represent an activity “undertaken by end-use customers, Load -Serving Entities, or their agents or representatives to influence the amount or timing of electricity they use”. It is not clear though because of the ambiguity of the definition particularly since it is not clear what “Activities undertaken by end-use customers” includes. Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
Consumers Energy Company	2. Establishing quantitative criteria for the Disturbance Recovery Period requires broadly based and in-depth analysis, which can be obtained only through full industry input. In R4.2 the change to allow the ERO to change the value is inappropriate. Response: The Response Team has struck the second sentences of 4.2 and 6.2.
Florida Municipal Power Agency	For Paragraph 321, a better solution would simply be to strike the sentence "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee", by doing so, any change to the 15 minutes or 90 minutes would be done through the ERO as part of the stakeholder process, meeting the intent of the directive that the ERO ought to do it, while retaining the stakeholder process. For Paragraph 330, spinning reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Spinning reserve is too important and under too much time pressure to not have direct System Operator control.For Paragraph 335, spinning reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Spinning reserve is too important and under too much time pressure to not have direct System Operator control. Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
Arizona Public Service Company	In the change of definition of Spinning Reserve, AZPS is uncomfortable with the language: "Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service" because it does not specify who has control. For Spinning Reserve, the control should be with the System Operator , as a quick response is necessary. For instance, an aggregator may offer demand management on a centralized basis using a control system under the control of the aggregator, but may require a phone call from the System Operator to activate. That may be too slow and not dependable enough for Spinning Reserve. AZPS

Organization	Question 4 Comment
	suggests using Direct Control Load Management instead of DSM for Spinning Reserves. Response: Please see our response in the Summary Consideration.
Oklahoma Municipal Power Authority	Paragraph 321: The proposed wording could bypass the stakeholder process. Request that the sentence "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee." The changes would still meet the intent of the directive while not removing from the stakeholder process. Paragraph 330, 335: Spinning reserve should invlude only Direct Control Load Management. Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
Indiana Municipal Power Agency	Question 1 - IMPA understands the use of ERO and Regional Entity; however, teh abbreviation ERO is not in the NERC functional model or in the NERC glossary of terms and the same is true for the term Regional Entity. If these terms are going to be used in NERC standards then they need to be defined by NERC in the functional model and/or the NERC glossary of terms. Question 2 and 3 - Demand Side Management encomposes many resources of which some can be diretly controlled and some cannot. The resources that can be directly controlled by an operator should be included in the contingency reserves. Response: Specific to the comment on changes regarding the Regional Entity, Version 5 Reliability Functional Model Technical Document, Ch. 15 indicates that: "NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC." We do not find using the term Regional Entity inappropriate. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.
CECD	Question 1. The change addresses the directive but is not appropriate. To support of the standards development process, a better modification is to delete the phrase, "approved by the NERC Operating Committee" rather than change the reference from NERC OC to the ERO in R4.2 and 6.2. Question 3. CECD suggests the following addition to the second sentence of the DSM definitions, which currently states "In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing." CECD would change the definition to state "In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the generation resource that would traditionally provide the function being met with DSM." Response: The Response Team has struck the second sentences of 4.2 and 6.2 as proposed. With respect to the comments on the changes to address the other paragraphs, please see our response in the Summary Consideration.

Organization	Question 4 Comment
US Bureau of Reclamation	The process to modify these standards is not following the accept andapproved process. The excuse that "FERC has expressed concern that industryand NERC have been less responsive than desired in providing a timelyresolution to those directives." offers no urgent or compelling reason for thisextraordinary step. It is suggested that NERC utilize the conventional standardmodification process for the changes requested by FERC. R4.2, 6.2. The last sentence "This period may be adjusted to better suit theneeds of an Interconnection based on analysis approved by the ERO." should beremoved. Modification to the standards would require the standard approvalprocess. To require that the ERO approve an analysis adds no improvement inreliability of the BES. Response: The Response Team is using a process that has been approved by the Standards Committee for this particular project. The Response Team has struck the second sentences of 4.2 and 6.2 as proposed.
Pepco Holdings, Inc. - Affiliates	The term “within the Disturbance Recovery Period following the contingency event” should be used to describe Demand Side Management Resources. Response: Please see our response in the Summary Consideration.
Dominion	While we agree that the change in paragraph 335 meets FERC directives, we believe that the definition of the term Demand Side Management needs further clarity, in particular the sentence that reads “In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.” We suggest something similar to “A Demand-Side Management activity must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.” Paragraph 1232 - in the definition for DSM, we suggest the word “Load; be replaced with “DSM Products”. In the future, loads many not be the only Demand side Product capable of assuming this role. Response: Please see our response in the Summary Consideration.

5. **Do you believe the changes made in response to the directive(s) contained in Paragraph 404 of Order No. 693 are both valid and address the directive(s)?**

404	The Commission clarifies that its direction to the ERO in this section is for it to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct control load management as regulating reserves, subject to the clarifications provided in this section.	BAL-005-1	Modified title of standards to be "Automatic Resource Control." Modified definition of "Automatic Generation Control." Added definition of "Automatic Resource Control." Modified definition of "Regulating Reserve." Modified Purpose (Section A 3) of standard. Modified Section B Requirements R2, R6, R7, and R15. Modified VSLs for R2, R7, and R15.

Organization	Question 5
Ameren	No
E.ON U.S.	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No
Indiana Municipal Power Agency	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Oklahoma Muncipal Power Authority	No
Santee Cooper	No

Organization	Question 5
Southern Company Transmission	No
Springfield Utility Board	No
US Bureau of Reclamation	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
Dynegy Inc.	Yes
Entergy Services	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SERC OC Standards Review Group	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

Organization	Question 5
Xcel Energy	Yes

6. Do you believe the changes made in response to the directive(s) contained in Paragraph 415 of Order No. 693 are both valid and address the directive(s)?

415	Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission's proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO's Work Plan. 410. Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area. 411. FirstEnergy states that Requirement R17 should include only "control center devices" instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term "check" in Requirement R17 needs to be clarified.	BAL-005-1	Modified Section B Requirement R17. Modified VSLs for R17. Deleted interpretations, as they have been incorporated into R17.

Organization	Question 6
Ameren	No
Consumers Energy Company	No
E.ON U.S.	No
ERCOT ISO	No
IESO	No
Midwest ISO Standards Collaborators	No

Organization	Question 6
NERC Standards Review Subcommittee	No
Northeast Power Coordinating Council	No
Springfield Utility Board	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Dominion	Yes
Entergy Services	Yes
Florida Municipal Power Agency	Yes
Georgia System Operations Corporation	Yes
Indiana Municipal Power Agency	Yes
Kansas City Power & Light	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
SERC OC Standards Review Group	Yes

Organization	Question 6
Southern Company Transmission	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Xcel Energy	Yes

7. Do you believe the changes made in response to the directive(s) contained in Paragraph 420 of Order No. 693 are both valid and address the directive(s)?

420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management	BAL-005-1	Modified title of standards to be “Automatic Resource Control.” Modified definition of “Automatic Generation Control.” Added definition of “Automatic Resource Control.” Modified definition of “Regulating Reserve.” Modified Purpose (Section A 3) of standard. Modified Section B Requirements R2, R6, R7, and R15. Modified VSLs for R2, R7, and R15.
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using nonfarm service	BAL-005-1	Modified Section B Requirement R5.

Organization	Question 7
Xcel Energy	No
IESO	No
Ameren	No
Georgia System Operations Corporation	No
Pepco Holdings, Inc. - Affiliates	No
E.ON U.S.	No
Florida Municipal Power Agency	No

Organization	Question 7
Northeast Power Coordinating Council	No
Santee Cooper	No
Dominion	No
Entergy Services	No
SERC OC Standards Review Group	No
Midwest ISO Standards Collaborators	No
US Bureau of Reclamation	No
Springfield Utility Board	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Dynegy Inc.	Yes
Kansas City Power & Light	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes

Organization	Question 7
Southern Company Transmission	Yes
Oklahoma Municipal Power Authority	Yes
Consumers Energy Company	Yes
Indiana Municipal Power Agency	Yes

Comments on the BAL-005 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P404, P415, and P420 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process. With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Comment
IRC Standards Review Committee	Paragraph 404 o The proposed changes exceed the Commission directive. The directive is to change the title not throughout the entire document, it was not to change the definition of AGC. o The requestor would have been more correct if the proposal were to change the title from Automatic Generation Control to something as simple as “Area Control Error” or “Balancing Control”. o As proposed, any automatic process used in balancing would come under this umbrella. For example, if a BA used UFLS resources to help maintain its ACE, then by this definition UFLS would be AGC. o The term AGC should be considered for removal. There is no one control system - indeed many if not all control systems have their unique characteristics. What the standard mandates is the calculation and use of Area Control Error (ACE). o AGC is a generic industry term for a control process and not specific to any one resource. It is a term used by vendors and academics and Control Theory books. Thus AGC programs do have meaning to those outside our standard process, and those who service our control programs. o Regarding the proposed conforming changes to the first sentence of the definition of regulating Reserve, we question the need for the second sentence in the definition. o The FERC mandate is that DSM explicitly be allowed to provide regulating reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the definition itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. Paragraph 415 o Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input into the standard development but only as part of the five year review process.

Organization	Comment
	o The proposed change introduces an undefined term “common reference”. Paragraph 420R5 imposes transmission-based responsibilities on the BA. That is simply wrong. The BA must plan and operate within the transmission constraints imposed by its TOPs. The proposed changes to R5 do not fully address the issues involved with the directive, which asks the ERO to “specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service.” The proposed changes to R5 describe the conditions (and causes for) that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this requirement be further developed, preferably by the BACSDT. Note a better solution would be to end the R5 requirement after the phrase “...provide replacement Regulation Service.”
ERCOT ISO	Q5 - The proposed changes address the directive, but the definition of DSM may be problematic if it differs from that which the Demand Response Data Availability System (DADS) has been developing. This is likely to be controversial and not low-hanging fruit.Changing from AGC to ARC is more complicated than just a title change and could cause confusion with standards applicability to AGC. There are system differences in deploying generation and deploying demand side resources.Q6 - The BAL-005-0.1b, regulatory approved on 5/13/2009, has sufficiently addressed the directive.
IESO	(1) Wrt changes for directives in Paragraph 404, we agree with the proposed definition of ARC and the proposed conforming changes to the first sentence of the definition of Regulating Reserve. However, we question the need for the second sentence in the latter definition, although we do not find it unacceptable. (2) Wrt the changes for directive in Paragraph 415, R17 says “Verify against a common reference” however it gives no indication of what an appropriate common reference is. Does this mean an entity can calibrate and check its primary frequency device against its backup? We imagine not. Clarification on the intent of this requirement would be appreciated as “common reference” is vague. (3) For the first part of changes for directive in Paragraph 420 involving defining ARC, please see our comment in (1), above. (4) Wrt the latter part of directive in Paragraph 420, we do not think the proposed changes to R5 fully address the directive, which asks the ERO to “specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service.” The proposed changes to R5 describe the conditions (and causes for) that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this requirement be further developed, preferably by the BACSDT.
Ameren	(a) The new definition introduces an acronym (ARC) that is already used by FERC for Aggregate Retail Customer (b) The proposed ARC definition should modify "Balancing Authority's interchange..." to "Balancing Authority Area's interchange ...", since BA does not have a schedulem rather a BAA does (e.g. one BA may operate multiple BAA).

Organization	Comment
	(c) In the Regulating Reserve definition add "to generation resources" between comparable and response in the last phrase. (d) In R5 - No regulating reserve should be on non-firm service (e) In R7, the team uses ARC but refers to generation.
Georgia System Operations Corporation	5a) We agree with the intent, but disagree with the wording. We believe that “controllable load resources” are included within DSM and thus the inclusion of both is unnecessary and confusing. If the language is retained we suggest that it be made consistent with BAL 002 (controllable load resources vs. controllable resources). We recommend:5b) Under Compliance 1.1 it refers to “their” Regional Entity. However, 1.1.1. refers to “the” Regional Entity. We recommend consistency. Also as a general statement the use of the term Regional Entity (RE) vs. Regional Reliability Organization (RRO) should be reviewed in all of these documents to ensure consistency. 6) BAL005 R5 is grammatically incorrect. Also we suggest removing the non-firm transmission language as it doesn’t add to the requirement. Stating it is no longer deliverable should suffice. 7) Under Compliance 1.1 it refers to “their” Regional Entity. However, 1.1.1. refers to “the” Regional Entity. We recommend consistency. Also as a general statement the use of the term Regional Entity (RE) vs. Regional Reliability Organization (RRO) should be reviewed in all of these documents to ensure consistency.
Pepco Holdings, Inc. - Affiliates	A BA does not monitor transmission constraints. Other standards already require a BA to follow the directions of a TOP or RC. This change is not needed.
E.ON U.S.	AGC is a well established, recognized, and understood standard industry term that E ON U.S. believes should not be summarily revised. Additionally, the suggested ARC term is misleading as this standard is only about regulation/load following. E ON U.S. suggests the following edits: Automatic Regulating Control (ARC): Automatic adjustment of resources and/or load serving a Balancing Authority Area to maintain the Balancing Authority’s interchange schedule plus Frequency Bias. In R 17 - strike the words “reporting or compliance” and “real-time error or” - the “ors” add unnecessary confusion to the requirement. Suggest revising to “R17. Each Balancing authority shall at least annually verify against a common reference the calibration of its frequency devices that provide input into the ACE equation.”
Florida Municipal Power Agency	For paragraph 404, Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative. For Paragraph 420, Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative in the definition of Regulating Reserve.

Organization	Comment
Northeast Power Coordinating Council	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. NERC should find an alternate method to address the Commissions' concern rather than simply "renaming" a widely, industry accepted and understood definition and concept such as "AGC."
Santee Cooper	Paragraph 404 and 420 - Any changes to NERC definitions should follow the ANSI approved standards process. Note for Paragraph 415 - Most frequency devices today receive their frequency from GPS satellites which derive their frequency from the National Bureau of Standards. Therefore, there is no need for devices to be calibrated.
Dominion	Paragraph 420 - While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be desired to assure reliability. We note that FERC did not require NERC revise the standard to allow the use of non-firm transmission service and believe that further stakeholder vetting of this is superior to the proposed revision to the standard. In the last sentence, "nonfarm" should be "non-firm."
Entergy Services	Paragraph 420 - While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be needed to assure reliability. The Balancing Authority receiving Regulation Service should be required to ensure that backup plans are in place to provide replacement Regulation Service should the service no longer be deliverable due to transmission constraints impacting the service, whether firm or non-firm. This change would meet the intent of the Commission directive, and improve reliability by ensuring backup plans exist.
SERC OC Standards Review Group	Paragraph 420 - While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be desired to assure reliability. We note that FERC did not require NERC revise the standard to allow the use of non-firm transmission service and believe that further stakeholder vetting of this is superior to the proposed revision to the standard. In the last sentence, "nonfarm" should be "non-firm."
Midwest ISO Standards Collaborators	The proposed changes actually exceed the Commission directive from paragraph 404. The change is only required to the title not throughout the entire document. Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input into the standard development but only as part of the five year review process. Therefore, there is no need to short circuit the NERC standards development process to make changes that should be handled through the five year review of the standard for a directive that has already been met. Furthermore, the proposed changes to R17 actually contradicts the interpretation. Specifically, the interpretation was clear that the

Organization	Comment
	devices that needed to be calibrated are those devices that feed ACE and time error calculations. The proposed changes include any device that provides frequency information to the operator through the clause “or frequency information to the operator”. At a minimum, this clause needs to be struck. We disagree with the changes to R5. First, the existing R5 already considers transmission constraints implicitly by stating “shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.” “Transmission constraints” is just one of a litany of reasons that the supplying Balancing Authority may not be able to provide regulation service. Why should transmission constraints be singled out as a reason? Secondly, BAL-001-0.1a still applies to the receiving BA regardless. That is, the receiving BA still must meet CPS1 and CPS2 regardless of why the regulation service is no longer available. We believe NERC simply needs the assistance of drafting team to explain the technical reasons why this is already addressed in the existing requirement. Modifying sub-requirement R17.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
US Bureau of Reclamation	The term "AGC" is used throught industry and the Reliability Standards.Unless the other standards are modified under this project, it is suggested that itwould be more expedient to modify the term AGC to allow for oher resources tobe included and not worry about the Generation part of the term. This will avoidconfusion with other standards, criteria, and procedures.In addition the definition cannot include all resources, just those that arecontrollable. The Definition should be rewritten as "Automatic Generation Control (AGC):Automatic adjustment of generation and other controllable resources in aBalancing Authority Area to maintain the Balancing Authority’s interchangeschedule plus Frequency Bias. ARC may also accommodate automaticinadvertent payback and time error correction."Examples of other Standards that use the term AGC include BAL 003, 004,005, 006, and BAL-Std-002.In addition the definition cannot include all resources, just those that arecontrollable.The Definition should be rewritten as "Automatic Generation Control (AGC):Automatic adjustment of generation and other controllable resources in aBalancing Authority Area to maintain the Balancing Authority’s interchangeschedule plus Frequency Bias. ARC may also accommodate automaticinadvertent payback and time error correction."Examples of other Standards that use the term AGC include BAL 003, 004,005, 006, and BAL-Std-002.
Springfield Utility Board	The use of the term "Demand Side Management" is overly broad, may lead to confusion with regard to application of standards, and confustion may reduce reliabilityThe current proposed language for Regulating Reserve is:Regulating Reserve: Reserve that is responsive to Automatic Resource Control, which is sufficient to provide normal regulating margin. Regulating Reserve may be comprised of generation, controllable load resources, Demand Side Management (DSM), or other resources that have comparable response

Organization	Comment
	characteristics.(Please refer to comments on BAL-002-1) SUB suggest the definition for Regulating Reserve be:Regulating Reserve: Reserve that is responsive to Automatic Resource Control, which is sufficient to provide normal regulating margin. Regulating Reserve may be comprised of generation, controllable load resources, Dispatchable Demand Side Management (DDSM), or other resources that have comparable response characteristics.
NERC Standards Review Subcommittee	#6. Disagree with proposed rewrite of R17. The use of the word "common" within common reference does not improve reliability. There are no common reference devices within the utility industry. This requirement is required to be written for all applicable entities to follow. Since there are many different frequency devices used (from satellite synched GPS receivers to 120 volt plug in models) within the industry, "common" needs to be replaced with "suitable" reference. This will allow applicable entities to calibrate their frequency devices as the manufacture recommends and thus, will improve reliability.
PacifiCorp	1. The word "compromised" under Regulating Reserve definition should be changed to "comprised". 2. Effective Date- Should be lengthened to at least one year to accommodate all of the documentation and system changes/screen updates etc. to modify AGC to ARC. 3. R5 -Request clarification of "transmission constraints".4. R7-modify the following: "manual control to adjust generation resources to maintain the Net Scheduled Interchange".
Southern Company Transmission	Paragraph 404 - AGC is an industry accepted term that has a specific meaning related to software and telemetry. Controlling load would/does require different software and telemetry. Reference to a new term Automatic Demand Control may be easier. The idea of controlling load for regulation would be a stretch. Doing it for contingencies or capacity makes some sense but regulation does not. One can vary the output of a generator to obtain moment-to-moment regulation but loads would not be expected to have that characteristic due to the real-time uncertainty/variability forced on the customer. A load is normally on or off unlike a generator. Paragraph 415 - Taken from previously posted interpretation in Appendix 1. Paragraph 420 - Seems reasonable to have a backup plan for lost regulation service due to transmission constraints.
Oklahoma Muncipal Power Authority	Paragraph 404: Regulation Reseve should only include Direct Control Load Management.
Consumers Energy Company	Please provide your opinion regarding the Paragraph 404 VSL changes: In Favor Changes for directives in Paragraph 415: Disapprove Comments: In R17, the phrase "or frequency information to the operator" should be deleted as an unnecessary expansion of scope. Please provide your opinion regarding the Paragraph 415 VSL changes: In Favor Changes for directives in Paragraph 420: Approve

Organization	Comment
	Please provide your opinion regarding the Paragraph 420 VSL changes: In Favor
Indiana Municipal Power Agency	Question 5 - Regulating Reserve should not include just any type of DSM. Only the controlled forms of DSM should be included in Regulating Reserves.

8. Do you believe the changes made in response to the directive(s) contained in Paragraph 565 of Order No. 693 are both valid and address the directive(s)?

565	The Commission agrees with ISO-NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.	EOP-001-2	Modified Section B Requirement R4. Modified VSLs for R4.

Organization	Question 8
Ameren	No
Consumers Energy Company	No
ERCOT ISO	No
IESO	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
Pepco Holdings, Inc. - Affiliates	No
Xcel Energy	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Dominion	Yes
E.ON U.S.	Yes

Organization	Question 8
Entergy Services	Yes
Florida Municipal Power Agency	Yes
Georgia System Operations Corporation	Yes
Indiana Municipal Power Agency	Yes
Kansas City Power & Light	Yes
National Grid	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Santee Cooper	Yes
SERC OC Standards Review Group	Yes
Southern Company Transmission	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

9. **Do you believe the changes made in response to the directive(s) contained in Paragraph 571 of Order No. 693 are both valid and address the directive(s)?**

571	As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that “insufficient transmission capability” could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.	EOP-001-2	Modified EOP-001 instead of EOP-002. Modified Section B Requirement R2.1.

Organization	Yes or No
NERC Standards Review Subcommittee	No
Ameren	No
Georgia System Operations Corporation	No
Florida Municipal Power Agency	No
National Grid	No
Xcel Energy	No
Entergy Services	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
E.ON U.S.	No
Oklahoma Municipal Power Authority	No
ERCOT ISO	No

Organization	Yes or No
Indiana Municipal Power Agency	No
United Illuminating Company	No
Midwest ISO Standards Collaborators	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Kansas City Power & Light	Yes
PacifiCorp	Yes
Santee Cooper	Yes
Springfield Utility Board	Yes
Dominion	Yes
Consumers Energy Company	Yes
Western Electricity Coordinating Council	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Northeast Power Coordinating Council	Yes
IESO	Yes

Comments on the EOP-001 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P571 directive will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process. With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

With regard to the P565 directive, The Response Team has considered the comments received on these modifications and determined that the directive has already been addressed in a previous revision to the standard. Upon Board approval of the remaining balloted and approved standards, this determination will be included in the filing presented to FERC regarding the other standards.

Organization	Question 9 Comment
IRC Standards Review Committee	Paragraph 565Although the proposed language in R4 addresses the directive, the language is loose and leaves room for interpretation. For example, What constitutes “consider”?; The proposed revised VSLs are too vague as they contain both “consider” ad “appropriate”, both of which are difficult to demonstrate or prove that the responsible entity comply with the intent of the requirement. The change introduces a need to prove that the functional entity “considered” Attachment 1. Either the change should remain and the industry should expect compliance entities to look for such proof; or the proposal should be dropped and allow the functional entities to include only the “applicable elements”.Further, the comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved. We believe that, through this effort, NERC has addressed FERC’s order to “examine whether to clarify this term in the Reliability Standards development process” and that it needs no further clarification at this time. The matter, we are confident, will be fully vetted in the next iteration of this Standard. Paragraph 571The proposed change to address paragraph 572 is inappropriate. In the FERC-restructured industry the BA is responsible for balancing supply and demand for the purposes of supporting system frequency, the BA does NOT have any responsibility for transmission other than to follow the constrains and directives imposed by its TOPs. This is an issue of fundamentals and the proposal must be rejected. The FERC directive is better served by simply dropping the BA from the requirement and dropping the constraint “for insufficient generating capacity”. The requirement would then be to have plans for emergencies. The fact is that emergency operating plans are focused on the root causes of the reliability issues and not on the generic cause of the issue.
NERC Standards Review Subcommittee	#9. R2 is applicable to Transmission Operators and Balancing Authorities and R2.1 states that they shall “develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity”. Currently TOPs and BAs have fulfilled this requirement. The proposed addition of “...including emergencies that arise due to a lack of transmission capacity and

Organization	Question 9 Comment
	those whose mitigation plans are hindered by the lack of transmission capability" does not enhance reliability. A Balancing Authority may not be registered as a Transmission Operator or have the ability to see how they impact the entire transmission system that they are a part of. A Balancing Authority may only have the ability to view some of the transmission system that they are a part of and not how they may affect the system overall. This addition is for a Transmission Operator only, the Balancing Authority should be deleted.
Ameren	(a) Section B, R2.1 - unnecessary. Whether the lack of generating capacity was due to a lack of transmission capability or the mitigation is hampered due to lack of transmission capability, it would be dealy with as an emergency due to insufficient generation either way. (b) Section A.5 - As the requirement R5, requires the emergency plan to be updated and reviewed annually, having an effective date that is less than a year away might result in a review between the annual reviews. if the effective date was the first day of the first calender quarter one year after approval, no extra reviews/update would be necessary. (c) R1 should include the recent interpretation. (d) R2.1 should add "inability of DSM to perform" after insufficient generating capacity (e) R2.1 - lack of transmission is undefined. Is this for n-1, n-2 or for n-7 events? (f) Attachmnet 1 needs to add a new item #16 - Consideration of DSM performance (g) VSL - Unless there has been numerous instances of non-compliance of EOP-001, the elements which cannot be determined to have been considered for each of the severity level should be one for Lower, four for Moderate, seven for High and more than seven for Very High (not labeled). The proposed nubers are consistent with the current VSL if the rounding is down.
Georgia System Operations Corporation	9) We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
Florida Municipal Power Agency	For Paragraph 571, the opportunity should be taken to "fix" R2.1, R2.2 and R2.4. R2.1 requires the TOP to Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity, which is the responsibility fo the BA, not the TOP. And R2.2 requires the BA to develop, maintain and implement a set of plans to mitigate operating emergencies on the transmission system, which is the responsibility of the TOP, not the BA. And, R2.4 conflicts with EOP-005 in that the TOPs develop the restoration plans, not the BA. This can easily be fixed by including applicability in R2.1 through R2.4, i.e., R2.1 Each BA shall develop ..., R2.2 Each TOP shall develop ..., R2.3 Each TOP and BA shall develop ..., and R4 Each TOP shall develop ...
National Grid	National Grid seeks clarification on "and those whose mitigation plans are hindered by a lack of transmission capability". The text seems confusing. Suggest deleting the text to enhance clarity.

Organization	Question 9 Comment
Xcel Energy	On 571, Xcel Energy couldn't find any reference to Para 571 in EOP-001.
Entergy Services	Paragraph 571 - We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
SERC OC Standards Review Group	Paragraph 571 - We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
Southern Company Transmission	Paragraph 571 - We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
E.ON U.S.	Paragraph 571 states that the ERO needs to "examine whether to clarify" the term insufficient transmission capability. FERC did not mandate insufficient transmission capability be included in the standard requirements.
Oklahoma Municipal Power Authority	Paragraph 571: Specific responsibilities should be better defined. i.e., R.2.1 - BA; R2.2 - TOP; R2.3 - TOP & BA; R2.4 - TOP
ERCOT ISO	Q8 - all the elements of Attachment 1 should be considered during the development of the emergency plan, however, only the chosen emergency plan elements should be assessed for compliance. We believe this is a compound requirement, not a low-hanging fruit, due to necessary industry vetting. Q9 - Modifications to EOP-001-2 R2.1 are unnecessary because R2.2 already addresses emergencies related to transmission capability, including those that may result in the inability to deliver energy from generation capacity.
Indiana Municipal Power Agency	Question 9 - It is not clear what kind of emergencies are being referenced with the new additional language for R2.1. If it is generation emergencies or operating emergencies, then the change should reflect which type of emergencies are to be considered. One could interpret the change to mean all emergencies that are possible which seems to be a huge task.
United Illuminating Company	United Illuminating agrees with the concept but has concerns with the phrase after "and those....". To us the FERC comment of inadequate transmission during the generation emergency is not properly addressed. We suggest changing the edit to: ....Operating emergencies for: 2.1.1 insufficient generation capacity 2.1.2. A lack of transmission capability

Organization	Question 9 Comment
	2.1.3 A lack of transmission capability while executing a plan responding to a generation emergency
Midwest ISO Standards Collaborators	We agree the changes from paragraph 565 are correctly implemented in the requirement. However, the corresponding changes to the VSLs exceed the scope of the directive and, thus, the scope of the SAR. The Commission did not direct changes to the VSLs from percentage of Attachment 1 elements included to the number of missing Attachment 1 elements compliance.While we agree that proposed changes appear to address directives in Paragraph 571, we do not understand how these changes further reliability and do not believe they are needed. When the BA is assessing the adequacy of its resources, it considers its whole portfolio which includes it generating fleet, purchases, sales and ability to receive those sales. There are many reasons collectively that a BA may experience an operating emergency due insufficient generator capacity. First and foremost, some event will likely have occurred (i.e. extraordinary record heat wave/cold snap, multiple generator failures, inability to import energy, transmission constraints preventing deliverability). Thus, if transmission constraints are preventing the BA from importing energy, the BA will look to its next available resource which may be shedding load. It makes no sense to single out one of the reasons for experiencing an emergency capacity energy shortage. To satisfy the Commission, we suggest that R2.1 could be modified from using “insufficient generating capacity” to “insufficient resource adequacy”. However, this suggestion should be vetted by a drafting team working specifically on EOP-001. Thus, this directive does not represent low hanging fruit. Modifying sub-requirement R2.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Dominion	Paragraph 571 - While we agree that the change in paragraph 571 meets FERC directives, we do not necessarily agree that the additional language improves the requirement. We suggest that R2.1 be re-written as follows: “Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand.”
Consumers Energy Company	Please provide your opinion regarding the Paragraph 565 VSL changes: Opposed Comments: Relative to R4 and the VSLs presented in the draft standard, some entities (particularly those who have entered into JRO’s regarding BAL-005, but share R4 responsibilities with other entities) may not have available the ability to apply one or more of the elements in Attachment 1. However, if the entity cannot demonstrate to the satisfaction of the Compliance Monitoring Authority that they have indeed considered these elements, and have, for demonstrable cause, determined that these elements are not “appropriate”, it will likely lead to disputes with the Compliance Monitoring Authority when evaluating compliance. “Appropriate” need to be better defined in the context of both R4 and the VSLs.

Organization	Question 9 Comment
	Changes for directives in Paragraph 571: Approve Comments: We recommend changing "insufficient generating capacity" to "insufficient resource capacity"
Western Electricity Coordinating Council	Requirement R4 includes the phrase “and if appropriate.” Who or what determines what is or isn’t appropriate? This phrase is vague. I suggest you clairify the applicable TOP and BA are the appropriate party to determine which applicable elements in Attachment 1-EOP-001-0 are appropriate to consider when developing an emergency plan.
Pepco Holdings, Inc. - Affiliates	The change did not clarify or enhance the requirement
Northeast Power Coordinating Council	This comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved.Through this effort NERC has addressed FERC’s order to “examine whether to clarify this term in the Reliability Standards Development Process” and that it needs no further clarification at this time. The matter, we are confident, will be fully vetted in the next iteration of this standard.
IESO	We agree that the proposed changes in R2.1 address the directive in Paragraph 571. However, the proposed language in R4, though literally addresses the directive, is loose and leaves room for interpretation as to what constitutes “consider”, and the proposed revised VSLs are too vague as they contain both “consider” ad “appropriate”, both of which are difficult to demonstrate or prove that the responsible entity comply with the intent of the requirement. More time is needed to develop a meaningful requirement and its associated compliance elements.

10. Do you agree that the directive in Paragraph 577 has already been addressed as noted above?

577	A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.	EOP-002-3 (No changes to standard)	This directive has already been addressed in IRO-006-4.

Organization	Question 10
Ameren	Yes
American Electric Power	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
E.ON U.S.	Yes
Entergy Services	Yes
ERCOT ISO	Yes
Georgia System Operations Corporation	Yes

Organization	Question 10
IESO	Yes
Kansas City Power & Light	Yes
Midwest ISO Standards Collaborators	Yes
National Grid	Yes
NERC Standards Review Subcommittee	Yes
Northeast Power Coordinating Council	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
SERC OC Standards Review Group	Yes
Southern Company Transmission	Yes
United Illuminating Company	Yes
Xcel Energy	Yes

11. Do you believe the changes made in response to the directive(s) contained in Paragraph 582 of Order No. 693 are both valid and address the directive(s)?

582	Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. 579. ISO-NE states that Requirement R2 essentially requires the same actions covered by ISO-NE Operating Procedure No. 4. ISO-NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO-NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO-NE procedures. ISO-NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.	EOP-002-3	Modified Section B Requirement R2.
582	Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.	EOP-002-3	Added Measures for R4, R5, R6, and R7.

Organization	Question 11
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
IESO	No
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
SERC OC Standards Review Group	No
Southern Company Transmission	No

Organization	Question 11
Xcel Energy	No
Ameren	Yes
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
Florida Municipal Power Agency	Yes
Georgia System Operations Corporation	Yes
Indiana Municipal Power Agency	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
United Illuminating Company	Yes

Organization	Question 11
Western Electricity Coordinating Council	Yes

12. Do you believe the changes made in response to the directive(s) contained in Paragraph 573 of Order No. 693 are both valid and address the directive(s)?

573	Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.	EOP-002-3	Modified Section B Requirement R6. Modified VSLs for R6.

Organization	Yes or No
Xcel Energy	No
NERC Standards Review Subcommittee	No
Ameren	No
Kansas City Power & Light	No
National Grid	No
E.ON U.S.	No
Southern Company Transmission	No
Springfield Utility Board	No
ERCOT ISO	No
Midwest ISO Standards Collaborators	No
Northeast Power Coordinating Council	No
American Electric Power	Yes

Organization	Yes or No
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Oklahoma Muncipal Power Authority	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
United Illuminating Company	Yes
PacifiCorp	Yes
Georgia System Operations Corporation	Yes
Florida Municipal Power Agency	Yes
Dominion	Yes
Entergy Services	Yes
SERC OC Standards Review Group	Yes
Indiana Municipal Power Agency	Yes
Western Electricity Coordinating Council	Yes
IESO	Yes

Comments on the EOP-002 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P573 directive will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process. With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

With regard to the P577 directive, the majority of commenters agree that this directive has been adequately addressed in Standard IRO-006-4 and hence no further action is required to close out this directive.

Regarding the P582 directive, most commenters agree with the proposed modifications. Some commenters suggest that M5 does not correspond with the wording in R5 and may in fact goes beyond the scope of R5. The Response Team agrees with their comment, and has revised M5 as follows:

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5)

Organization	Question 12 Comment
IRC Standards Review Committee	Paragraph 582The proposed changes do not address the underlying problem with the entire standard which is how to write emergency standards related to system control. What is an emergency state for a BA? If the BA must balance supply and demand both instantaneously and "on average" then when does an emergency begin for the BA? In Balancing, one could argue the only issue is does the BA have enough supply and if not then shed load. Too much supply is handled by exercising its authority over GOPs. Such fundamental issues must be discussed before expediting minor adjustments. The change to R2 does nothing to clarify what it means to "reduce risk" or what "as required" means (does this mean if something bad happened that the entity by definition is non-compliant since it obviously didn't do "what was required to address the problem"?). How is risk measured? Measure 2 requires the entity to show that its acts were in "conformance" with its plans. Does that preclude a system operator from varying with a particular step in its own emergency plans?Does approval of the proposed changes constitute an approval of EOP-002? This is important because:R4, R5, R6 are examples of requirements that need a major rewriting, or at least major discussion. R4 imposes an immeasurable "anticipation" step. Without being able to measure "anticipation" this requirement has no meaning. An entity that did not "anticipate" the emergency cannot be held non-compliant with R4! R5 treats frequency control as if it were a fine-tuning process. Moreover, as written R5 places a ceiling on how much real power may be exchanged over and above its scheduled interchange. Since ACE already introduces a bias for the frequency, it would seem that "any" non-

Organization	Question 12 Comment
	zero ACE would represent non-compliance to this requirement. The standard was written with regard to correcting frequency - but in the mandatory compliance world the “intentions” of the entity is not measureable so any error could be assumed to be used to assist frequency. R6 is unclear. What constitutes “immediately”? If all remedies are optional, then no remedy is required, making compliance a moot point. The proposed M5 does not correspond to the condition stipulated in R5. The proposed Measure appears to expand the scope of the Requirement in regard of utilization unilateral generation adjustment. We suggest the latter part in M5 to be reworded as “...and that in its attempts to return Interconnection frequency to normal, it did not unilaterally adjust generation beyond that supplied through frequency bias action and Interchange Schedule changes.” Paragraph 573The proposed changes do not change the requirement. Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to be a tool for control. The SAR requestor proposes to meet this directive by inserting DSM into a list. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. Response: Specific to the comment on Paragraph 582, this project was initiated to develop standard changes as indicated in the listed directives. Making changes to other parts of the standard that are not affected by the directives is beyond the scope of this Project. Implementing and approving the proposed changes do not imply that the standard will not be revised in the future to improve the overall quality and clarity of the standard. With respect to M5, the Response Team agrees with your comment, and has revised M5 as follows: M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection’s frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5) Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
NERC Standards Review Subcommittee	#12. R6.3 and R6.8 should be replaced by using Direct Control Load Management (DLCM). As described in the NERC Glossary of terms: DLCM is “Demand-Side Management (DSM) that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand”. Per NERC Glossary of terms, Demand Side Management is undertaken by the Load Serving Entity or its customers, whereas DCLM is under the direct control of system operators. NERC’s Glossary of terms goes on to define a system operator as “an individual at a control center (BA, TOP, GOP, RC) whose responsibility it is to monitor and control that electric system in real time”. DCLM should be used in place of DSM since it has more

Organization	Question 12 Comment
	applicable entities per NERC definition. Response: The Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
Ameren	(a) R 6.8 - Unknown technologies are not "technically feasible". Delete this sub requirement. (b) In Attachment 1, Alert 1 - does "All Available Resources" include DSM? If resources are comparable, why woudn't it be? Response: The Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
Kansas City Power & Light	Directive 573:Sub-requirement R6.8 is ambiguous and subject to interpretation and recommend removal. The other sub-requirements R6.1 through R6.7 are sufficiently comprehensive as available recovery actions and the removal of R6.8 does not compromise the response to the directive language to be addressed.In addition, although not one of the changes submitted, requirement R6 should be considered modified to reflect language that targets maintaining a balance of energy resources and energy obligations in real time. The current references to Control Performance and Disturbance Control Standards over longer operating ranges does not accurately reflect the need for immediate operator actions. Recommend modifying the language to “cannot maintain ACE within Lsub10 limits, then . . .”. Response: The Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.
National Grid	In Order 693, the Commission correctly determined that “With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO’s Reliability Standards development process to ensure that their opinions are considered. Such changes are appropriately considered “low hanging fruit” and should be will be fully vetted in the next iteration of this standard. Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. Response: The Response Team thanks the commenter for the thoughtful comments. These comments touch on areas that are beyond the scope of this project. We will forward your comments to the NERC Standards Committee for its consideration.

Organization	Question 12 Comment
	Specific to the comment on Paragraph 582, the proposed changes to R2 and the addition of M5 and other compliance elements were directed by the Commission and the ERO must comply. In response to other commenter's suggestion, the Response Team has revised M5 as follows: M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5)
E.ON U.S.	In paragraph 582, FERC says to "consider" Measures. E ON U.S. believes the added Measures are not mandated by FERC. E ON U.S. also believes these added Measures neither improves reliability nor changes the obligation of the BA to provide evidence upon request. In response to paragraph 573, E ON U.S suggests using the term "technically feasible resource options," not "any available alternative technologies." "Any available alternative technologies" is too broad & omits the technical requirements qualification required by FERC. E ON U.S. suggests the following edits: R6.8. Deploying any technically feasible resource options not included above that are designed to supply energy to or reduce demand on the Bulk Electric System. Response**:** Specific to the comment on Paragraph 582, the proposed changes to R2 and the addition of M5 and other compliance elements were directed by the Commission and the ERO must comply. Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
Southern Company Transmission	Paragraph 577 - Addressed in IRO-006. Does something need to be filed with NERC or FERC to explain that? Paragraph 582 - R2- Not sure words clarify anything. What if two actions are required under the plan for a situation but they only took one. Should it not be something like " ... shall take actions required and appropriate for an emergency situation as described in its capacity and emergency plan or substitute alternative actions as appropriate to the current situation based on operator discretion to reduce risks to..."If this is changed, then M2 needs to change to reflect any changes. Paragraph 573 - Not sure why R6.3 is needed. Demand Side Management could be put in the list for R6.7 and be less controversial. As stated earlier, although FERC states that "demand response covers considerably more resources than interruptible load" it is not clear to any reader what that might be. Expect confusion to cause problems with proposed changes being low hanging fruit.Note: Demand-side management is explicitly listed in Alert 2 in current Attachment 1 Response: Specific to Paragraph 577, NERC will file with FERC to explain that this directive has been addressed in IRO-006-4. Specific to Paragraph 582, the Response Team does not think the proposed alternate wording adds any clarity to the wording proposed in the draft standard, which already provides the flexibility needed to address the energy/capacity emergency situation while adhering to the entity's

Organization	Question 12 Comment
	emergency plan. Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to address this directive will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
Springfield Utility Board	Please refer to BAL-002 and BAL-005 commentsR6.3 is proposed to state "R6.3. Deploying all available Demand-Side Management options,""Demand-Side" is not a term in the NERC definitions. The dash should be removed. Demand Side Management should be changed to Dispatchable Demand Side Management.This should be changed toR6.3 is proposed to state "R6.3. Deploying all available Dispatchable Demand Side Management (DDSM) options," Response: The Response Team has considered the comments received and determined that modifications to R6 to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
ERCOT ISO	Q11 - Proposed revisions to R2 appear to address the directive, however the language comes short of criteria for a good requirement. It is not clear when the action is required or when it is appropriate. This may prove to be controversial. Q12 - This would require significant developmental work to describe how to determine technically equivalent performance. The Requirement 6.3 change includes the use of the defined term DSM, which needs to be in sync with the effort of the Demand Response Data Availability System (DADS) team. Response: Specific to R2, the project was initiated to address the outstanding directives, and the Response Team believes the language is sufficiently clear to be enforceable. Improving general standard quality is outside of the scope of this project, but will be considered in future revisions. Specific to R6 and its sub-requirements, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
Midwest ISO Standards Collaborators	The changes to R2 are unnecessary and only state the obvious. A capacity and emergency plan must identify when it is appropriate and required to take actions. Adding the clause to R2 provides no reliability benefit. Furthermore, the directive only requires the ERO to address ISO-NE concern, not to necessarily modify the standard. The concern should be addressed by a simple explanation that if their plan allows them to skip steps, they have met the requirement by having a plan and implementation of their plan allows them to implement only what is necessary. We disagree with adding Measures through this standards action. FERC was clear in paragraph 616 from Order 693 that determination of the need for a requirement to have a measure was at the ERO's discretion. Thus, measures do not appear to be a major concern of FERC and making changes to measures will not demonstrate a commitment to complete directives from Order 693. Thus, there is no need to make

Organization	Question 12 Comment
	changes to measures through an expedited process. Measurement 5 is fundamentally incorrect. R5 is intended to limit a BA's assistance on the Interconnection to the frequency response obligation established by the frequency bias settings for a few minutes (up to 15) after the loss of a resource. Measurement 5 reads to limit all Interconnection assistance and could be construed as limiting the import schedules. The wording should be made parallel to the requirement. We suggest: "The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)"We do not believe the directive in paragraph 573 represents low hanging fruit. We are supportive of using DSM but we believe a drafting team needs to carefully work through addressing this directive to avoid unintended consequences. Based on the proposed definition of DSM in BAL-002, it is not clear if interruptible load is distinctly differently or one of the various types of DSM. If it is one of the various types of DSM, then R6.4 is duplicative of R6.3. Further changes may be required to the standard to address the directive as well. For example, why would R4 not include notifying the "end-use customers, Load-Serving Entities, or their agents or representatives" to anticipate the need to call upon DSM?Adding sub-requirements R6.3 and R6.8 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. Response: Specific to R2, the project was initiated to address the outstanding directives, and the Response Team believes the language is sufficiently clear to be enforceable. Improving general standard quality is outside of the scope of this project, but will be considered in future revisions. Specific to the comment on M5, the Response Team has revised M5 as follows: M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5) Specific to R6 and its subrequirements, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.

Organization	Question 12 Comment
Northeast Power Coordinating Council	This comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved.Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. In Order 693, the Commission correctly determined that “With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO’s Reliability Standards development process to ensure that their opinions are considered. Such changes are appropriately considered “low hanging fruit” and should be will be fully vetted in the next iteration of this standard. Response: Specific to R2, the proposed changes are intended to comply with directives as stipulated. We are not certain that the ISO-NEs view now expressed fully takes care of the FERC’s directive in Paragraph 582. Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
PacifiCorp	1. R6.8 Internal comment---This requirement illustrates the need for additional DSM resources. 2. M5-Request clarification. Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process.
Georgia System Operations Corporation	10) While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. 11) While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. 12) While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6

Organization	Question 12 Comment
	and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process. Your proposal will be retained for future consideration.
Florida Municipal Power Agency	For Paragraph 577, we "ABSTAIN", as we do not understand why this is being balloted since there is no change. Response: We conducted the ballot to seek the industry's concurrence that the directive has been taken care of.
Dominion	Paragraph 582 - While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process. Your proposal will be retained for future consideration.
Entergy Services	Paragraph 582 - While we do not believe that the sub-requirements of R6 are intended to be executed in order, we suggest that R6.8 should be ordered prior to reducing load. Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process. Your proposal will be retained for future consideration.
SERC OC Standards Review Group	Paragraph 582 - While we do not believe that the sub-requirements are intended to be executed in order, we suggest that the sub-requirement that includes reducing load should always be last. Response: Specific to Paragraph 573, the Response Team has considered the comments received and determined that modifications to R6 and its subrequirements to address the directive in Paragraph 573 will require more extensive discussion than can be addressed within this effort. The changes intended for this directive have been removed from consideration during the balloting process. Your proposal will be retained for future consideration.
Indiana Municipal Power Agency	Question 10 - Abstain. If this issue has been addressed, why is it being covered in this area of commenting? Response: We conducted the ballot to seek the industry's concurrence that the directive has been taken care of.
Western Electricity Coordinating Council	Requirement R2 includes the phrase "and as appropriate." Who or what determines what is or isn't appropriate? We agree with the concept that not all actions included in the plan need to be implemented for every event, but this phrase is vague. Suggest clarifying tha that the BA is

Organization	Question 12 Comment
	the appropriate party to determine which actions are appropriate. Response: The proposed changes are intended to comply with directives as stipulated, and it is the Response Team's belief that the language proposed is sufficiently clear to be enforceable. Improving general standard quality is outside of the scope of this project, but will be considered in future revisions.
IESO	Specific to the changes to the Measures, etc. to comply with the directive in paragraph 582, we do not agree with the proposed M5 since the second part does not correspond to the condition stipulated in R5. The proposed Measure appears to expand the scope of the Requirement in regard of utilization unilateral generation adjustment. We suggest the latter part in M5 to be reworded as "...and that in its attempts to return Interconnection frequency to normal, it did not unilaterally adjust generation beyond that supplied through frequency bias action and Interchange Schedule changes." Response: Other commenters have also expressed a similar concern. The Response Team has revised M5 as follows: M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (R5)

13. Do you believe the changes made in response to the directive(s) contained in Paragraph 601 of Order No. 693 are both valid and address the directive(s)?

601	We also note that APPA raise(s) issues regarding coordination of trip settings and automatic and manual load shedding plans. The Commission directs the ERO to consider these comments in future modification to the Reliability Standard through the Reliability Standards development process. 598 In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners.	EOP-003-2	Modified Section B Requirement R3.

Organization	Question 13
Ameren	No
American Electric Power	No
Arizona Public Service Company	No
Central Lincoln	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No

Organization	Question 13
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
NERC Standards Review Subcommittee	No
Northeast Power Coordinating Council	No
Oklahoma Muncipal Power Authority	No
PacifiCorp	No
Santee Cooper	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
United Illuminating Company	No
Xcel Energy	No
CECD	Yes
National Grid	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Western Electricity Coordinating Council	Yes

14. Do you believe the changes made in response to the directive(s) contained in Paragraph 603 of Order No. 693 are both valid and address the directive(s)?

603	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-003-1 through the Reliability Standards development process that requires periodic drills of simulated load shedding.	EOP-003-2	Added Section B Requirements R9 and R10. Added VSLs for R9 and R10.

Organization	Yes or No
NERC Standards Review Subcommittee	No
Ameren	No
Northeast Power Coordinating Council	No
Georgia System Operations Corporation	No
National Grid	No
Western Electricity Coordinating Council	No
Arizona Public Service Company	No
Consumers Energy Company	No
Kansas City Power & Light	No
Florida Municipal Power Agency	No
E.ON U.S.	No
Dominion	No
Entergy Services	No

Organization	Yes or No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Santee Cooper	No
American Electric Power	No
Central Lincoln	No
ERCOT ISO	No
Indiana Municipal Power Agency	No
CECD	No
United Illuminating Company	No
Oklahoma Municipal Power Authority	No
PacifiCorp	No
IESO	No
Midwest ISO Standards Collaborators	No
Pepco Holdings, Inc. - Affiliates	Yes
Xcel Energy	Yes

Comments on the EOP-003 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P601 and P603 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Question 14 Comment
IRC Standards Review Committee	Paragraph 601Taken in isolation the concept of adding a list of entities with whom the TOP and BA must coordinate is reasonable. Taken in conjunction with the entire standard the change becomes a de facto acceptance of the requirement as written. Regarding R3, the concept of “coordination” is vague and undefined. There are several issues that make this seemingly trivial request more complex than the requestor makes it out to be. o The standard itself is included in Project 2007-01 o The concept of “coordination” is vague and undefined o There is no measurement nor VSL for R3 o Who is non-compliant if one or more of the list entities does not participate? o Aren’t all TOPs and BAs in an interconnection “interconnected”? Paragraph 603The directives ask for including requirement for periodic drills of simulated load shedding. The wording in R8 asks for testing the load shedding plan through simulation. There was already a dispute on the interpretation of “simulation” (in a recently posted interpretation), which may be interpreted as using simulator or computer simulation program. The directive simply requires a “drill” which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation. Requirement R8 as written goes outside of the scope of the directive. Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive. Further, which entities need to participate in the testing of the plan and the required testing details need much more time and industry discussion to develop, and hence should be developed through the normal process not through this much abbreviated process. It follows that we do not agree with the VSLs for this Requirement.There is a coordination concern with Project 2007-01 that is currently underway. Project 2007-01 whose latest draft is being posted for balloting and comment proposes to revise EOP-003 by removing UFLS reference from the latter standard. If the PRC-006/EOP-003 pair is approved, it will render the version being used for making changes to address the

Organization	Question 14 Comment
	low-hanging fruit directive invalid. Further, there should not be two versions of the same standard to be posted for balloting at the same time. We suggest that changes to EOP-003 to address the directives in Para. 601 and 603 be withheld until after the Board adopts the revised PRC-006-1 and EOP-003-1 if they receive ballot approval. If they fail, such work should be assigned to the Project 2007-01 SDT for inclusion in the next draft.
NERC Standards Review Subcommittee	#13. R3 requires a TOP and BA to coordinate load shedding plans with each interconnected TOP and BA along with Regional Entities within whose regions they operate and RC(s) associated with overseeing the operations of the BA or TOP, plus GOs within the appropriate BA area or TOP area. This multiple coordination effort harms reliability of the BES and will only add confusion and frustration. Many TOPs and BAs are registered within multiple regions and this proposed continent wide reliability standard does not take into consideration how present day entities support the BES, daily.The following is a proposed rewrite to R3 and its sub requirements: R3. Each Transmission Operator and Balancing Authority shall coordinate manual load shedding plans with at least one of the following: R3.1 Physically connected Transmission Operators and Balancing Authorities or R3.2 Regional Entities within whose regions they operate or R3.3 Reliability Coordinator(s) associated with overseeing the operations of the Balancing Authority Area or Transmission Operator Area and R3.4 Generator Owners within the Balancing Authority Area or Transmission Operator Area, as appropriate. The above rewrite now gives clarity with whom the TOP and BA is required to coordinate their manual load shedding plans with. Manual is inserted since UFLS and UVLS are noted within other standards and all load shedding (outside of UFLS and UVLS) is done manually. Presently many entities follow the Regional Entity's plan and this fulfills all sub requirements of R3. #14. R8 (Note this requirement does not match up with NERCs Comment column above) Request that in order to prove clarity, R8 be rewritten as FERC stated within Order 693 to require periodic drills of simulated load shedding. R8 to read "At least annually, each Transmission Operator and Balancing Authority shall simulate load shedding as stated within their respected load shedding plan". This rewrite will enable the TOP or BA to simulate load shedding as they plan, not practice load shedding by the use of simulation. #14. R9 (Note this requirement does not match up with NERCs Comment column above) R9 should be deleted in its entirety since paragraph 603 states " 603. The Commission approves proposed Reliability Standard EOP-003-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and Â§ 39.5(f) of our regulations, the Commission directs the ERO to develop

Organization	Question 14 Comment
	a modification to EOP-003-1 through the Reliability Standards development process that: (1) includes a requirement to develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on an overarching criteria that take into account system characteristics and (2) requires periodic drills of simulated load shedding”. R9 does not address the Commissions interests.
Ameren	(a) R3.4- This standard does not apply to Generator Owner, but the requirement is to coordinate with them. What reason would GO have to comply if there are no consequences of non-compliance. It will be difficult to coordinate with a GO having no measure for compliance (b) On the other hand, R3 does not require to coordinate with LSE and DP, but R9 does. Again the standard does not apply to LSE or DP and for that reason would be difficult to coordinate for R9. (c) R8 - what does "test through simulation " mean? Does that mean table top drills, actual signals but not implemented, load flow and dynamic model simulations? This requirement is vauge.
Northeast Power Coordinating Council	1. These new provisions are in conflict with the proposed PRC-006 NERC standard, and should be addressed in this forum. 2. There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9. 3. What are personnel deployment drills? Are these applicable to automatic load shedding? 4. Requirement R9 is not in the directive; and is outside the scope of the directive.
Georgia System Operations Corporation	13) IF TOPs and Bas are required to coordinate with RCs, REs, and GOs, they should be included as applicable entities and have a requirement to participate in the coordination of plans with their TOPs and BAs? 14a) Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process. 14b) Paragraph 603 - The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. Tabletop exercises should be acceptable. R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard. 14c) It isn’t clear what Measure M2 refers to now. The VSL requirement changes appear to be mis-numbered.

Organization	Question 14 Comment
National Grid	o National Grid seeks clarification and possible examples for the term “simulation”. o There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9 where LSE and DP have been added but are not included in the Applicability section. o What are personnel deployment drills? Are these applicable to automatic load shedding? o Requirement R9 is not in the directive; and is outside the scope of the directive.
Western Electricity Coordinating Council	Agree with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. Once every two years is too often for tests. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. Suggest a similar time requirement here.Also believe that new Measures should be developed for any added Requirements.
Arizona Public Service Company	AZPS believes that R2 and R3 should be removed from this standard. In addition, AZPS agrees with the comments of FMPA as follows: there are two versions of a revision to EOP-003 out for ballot at the same time (now), one as part of this Order 693 effort and another as part of the PRC-006, Project 2007-01 effort. The revisions do not complement each other but rather conflict with each other. The PRC-006 team is proposing to remove UFLS from the EOP-003 standard because it really does not belong there and belongs instead in PRC-006. In all honesty, UVLS ought to also be removed from EOP-003 in favor of PRC-010 as well, but, that will presumably be left to another drafting team (presumably Project 2008-02). But, the real point here is that EOP-003 is broken, ought to only refer to manual load shedding, not automatic (automatic should be handled in PRC standards), and the two teams have made conflicting proposals on how to fix EOP-003 that ought to be coordinated. EOP-003, as proposed, is disturbing in the sense that it requires simulation of the effectiveness of load shedding plan (R7- new) and test of load shedding plan (R8-new), without specifying the scope and clarifying what it means.
Consumers Energy Company	Changes for directives in Paragraph 601: Disapprove Comments: Fundamentally, automatic load shedding must be designed and implemented in the planning time horizon, not in any of the operational time horizons, in that it must be implemented via installation of equipment in substations. Therefore, EOP-003 continues to duplicate, to some degree, NERC Standard PRC-007, in that the elements established for automatic load shedding per EOP-003 are the same as those generally addressed in Regional UFLS programs, and probably resemble those elements likely addressed in a NERC-wide UFLS standard, when such a standard is promulgated. This seems to raise the specter of double jeopardy. Similar concerns apply regarding automatic load shedding relative to NERC Standards PRC-010 and PRC-021. We suggest that R4 address frequency and voltage related factors only to the degree that similar functions related to UFLS/UVLS programs as discussed above are determined to not be adequate, and would be implemented via SCADA or other operator-triggered standards.

Organization	Question 14 Comment
	Please provide your opinion regarding the Paragraph 420 VRFs and VSLs: Opposed Comments: Fundamentally, automatic load shedding must be designed and implemented in the planning time horizon, not in any of the operational time horizons, in that it must be implemented via installation of equipment in substations. Therefore, EOP-003 continues to duplicate, to some degree, NERC Standard PRC-007, in that the elements established for automatic load shedding per EOP-003 are the same as those generally addressed in Regional UFLS programs, and probably resemble those elements likely addressed in a NERC-wide UFLS standard, when such a standard is promulgated. This seems to raise the specter of double jeopardy. Similar concerns apply regarding automatic load shedding relative to NERC Standards PRC-010 and PRC-021. We suggest that R4 address frequency and voltage related factors only to the degree that similar functions related to UFLS/UVLS programs as discussed above are determined to not be adequate, and would be implemented via SCADA or other operator-triggered standards.
Kansas City Power & Light	Directive 601:It is inappropriate to include Regional Entities as an entity to coordinate load shedding. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to coordinate operating actions or schemes as defined in this Standard EOP-003. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified. Directive 603:It is unclear as to the extent a "simulation" is intended in requirement R8. Recommend clarifying the simulation as a form of modeling and not intended as exercise of actual actions. In addition, what is to be simulated here? There are two forms of load shedding action. Automatic load shedding based on frequency and/or voltage and manual load shedding by operator action. What is the intention? It is unclear what "test" in requirement R9 represents. Recommend clearly indicating the intent is a test of the plans under table-top drills or other modeling techniques.
Florida Municipal Power Agency	For Paragraph 601, this is probably a case of miscommunication between Drafting Teams under tight time pressure, but, there are two versions of a revision to EOP-003 out for ballot at the same time (now), one as part of this Order 693 effort and another as part of the PRC-006, Project 2007-01 effort. The revisions do not compliment each other but rather conflict with each other. The PRC-006 team is proposing to remove UFLS from the EOP-003 standard because it really does not belong there and belongs instead in PRC-006. In all honesty, UVLS ought to also be removed from EOP-003 in favor of PRC-010 as well, but, that will presumably be left to another drafting team (presumably Project 2008-02). But, the real point here is that EOP-003 is broken, ought to only refer to manual load shedding, not automatic (automatic should be handled in PRC standards), and the two teams have made conflicting proposals on how to fix EOP-003 that ought to be coordinated.

Organization	Question 14 Comment
	For Paragraph 603, the Commissions language is much clearer than the proposed R8 and R9. The commission directed "periodic drills of simulated load shedding", which means they want us to perform drills. R8 and R9 changes the object to "test" which introduces ambiguity that is wide-open to numerous interpretations. R8 and R9 should be revised to clearly show that "drills" are required as directed by the Commission. "Drills" are much less open to interpretation than "tests". In addition, the Commission was clear that the "drill" they are directing ought to include as part of the exercise "simulated load shedding", which is clear that the Commission does not expect engineering simulations, but rather a drill that simulated the decision making environment operators would be exposed to. R8 as proposed introduces the same ambiguity that is currently within EOP-005-1 R7 by saying "test their load shedding plans through simulation". This introduces the ambiguity that has spurred requests for interpretation in EOP-005-1 R7: is simulation a "drill" or an engineering computer simulation? While FMPA believes that EOP-005-1 R7 also means a "drill", compliance has believed otherwise. Here it is clearly a drill that is required. We ought to stay away from words that add ambiguity such as "simulation" and "test" and stick with words that are more clear, like "drill". (Note that the ballot refers to R9 and R10 whereas the proposed draft adds R8 and R9 and there is no R10, we assume this is a typo in the ballot)FMPA opposes the opinion regarding Paragraph 603 VSL Changes. Note that the question title says Paragraph 420, which we assume to be a typo and should refer to Paragraph 603. See comments to "Changes for Directives in Paragraph 603" (above).
E.ON U.S.	In paragraph 601 FERC says to “consider the comments...in future modification”, not to actually change requirements. The adding of requirements and/or sub-requirements is therefore unnecessary to meet the directive. The revision to R3.4 adds Generator Owners when the need for load shedding coordination needed between a TOP/BA and GOs arises when load is shed automatically based on frequency or voltage levels. This should be covered under other standards. It is not clear to E ON U.S. why the TOP/BA need to coordinate a manual load shed program with the GO. There are errors in the numbering for VSLs R8, R9, and R10. There is no R10 in the Requirements Section.
Dominion	Paragraph 601 - Although we agree that the changes meet the FERC Directive, we suggest the this version is premature given that Project 2007-01 (Underfrequency Load Shedding) contains requirements related to under-frequency load shedding, already contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft. We suggest the SDT take no action on this revision pending the outcome of balloting in Project 2007-01. Paragraph 603 -R8 The term “simulation” needs to be better defined to allow entities to comply with the intent without increasing the potential for shedding load to be inadvertently implemented. R9 expands the applicability to load serving entities and distribution providers, which are not listed in the Applicability section of this draft standard. We suggest the SDT either add these entities to the Applicability section or remove these entities from R9.

Organization	Question 14 Comment
Entergy Services	Paragraph 601 - Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process. Paragraph 603 - The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard and should not be included. Paragraph 603 concerns the simulation of and periodic drills for load shedding plans. The added requirements R8 and R9 addressing Paragraph 603 contain the “Time Horizon: Long-Term Planning, Operations Planning”. We believe these requirements do not apply to Long-Term Planning Time Horizon and that term should be deleted.
SERC OC Standards Review Group	Paragraph 601 - Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process. Paragraph 603 - The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard.
Southern Company Transmission	Paragraph 601 - Requirement R3 does not clarify the current ambiguity about what type of load shedding - automatic or manual. R1 is clearly Automatic and APPA and ISO-NE talk in Order 693 about “trip settings” which imply automatic as well. Furthermore, the UFLS drafting team has already proposed changes to EOP-003 that are not coordinated with these changes to remove UFLS completely from this standard into of PRC-006. That set of changes to those standards will be balloted simultaneously with these changes based on the dates on NERC’s website. Paragraph 603 - NERC Comments note revisions for R9 & R10, but R10 does not exist on published copy of draft. R8 & R9 appear to be the ones added. Also has incorrect references to R9 & R10 in VSL. And again, what type of load shedding? In R8, the term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load.
Santee Cooper	Paragraph 601 - the meaning of “coordinate” needs to be clarified. In addition, EOP-003-1 is in the pre-ballot review period for the

Organization	Question 14 Comment
	third draft and those changes are not incorporated into this draft. It would be best to wait and let industry vet EOP-003-1 first before making more changes to this standard. Paragraph 603 - FERC directed these changes go through Reliability Standards process. We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process. In addition, EOP-003-1 is in the pre-ballot review period for the third draft and those changes are not incorporated into this draft. It would be best to wait and let industry vet EOP-003-1 first before making more changes to this standard.
American Electric Power	Paragraph 601With respect to R3.4., AEP recommends that it would be more applicable for the coordination to occur between Transmission Operator (TOP) or BA and Generator Operators rather than Generation Owners. In many cases, these are separate entities and it is our experiences that the GO is not always the appropriate entity regarding the sharing of these plans.AEP does not see the benefit in sharing the load shedding plans with the RE. Based on the division of responsibilities, some RE's mainly only have compliance staff and do not have expertise with addressing the plan. If a particular RE wanted to see the plan, AEP would work with that entity. Creating a process to send data to entities that do not need the information, simply for the sake of demonstrating compliance, does not advance the goal of increasing reliability.Paragraph 603Drills should be and are already covered under the training standards. There is no need to have redundant requirements that create overlaps. Furthermore, the addition of R9 does not seem to be justified as part of the FERC directive in Paragraph 603.
Central Lincoln	Project 2007-01 is also rewriting this standard, and the two versions conflict.
ERCOT ISO	Q13 - Coordination with the Regional Entities may not be universally applicable due to variations in the way Regional Entities are organized. Regional Entities need to know about the load shedding plans, but the planning and development may not need to include Regional Entities unless they perform such function.The RC should be made aware of load shedding plans and capabilities, but actual coordination should likely be with the PC. The NERC Project 2007-01 UFLS proposes that the PC determines load shedding programs.- Q14 - The directives ask for including requirement for periodic drills of simulated load shedding. The wording in the proposed R8 asks for testing the load shedding plan through simulation. The directive simply requires a "drill" which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation. Requirement R8 as written goes outside of the scope of the directive.R9 is not asked for by the directive.
Indiana Municipal Power Agency	Question 13 - Under the UFLS Project, the UFLS SDT has removed UFLS from this standard draft posted for commenting and voting in project 2007-01. The side by side commenting and balloting of the same standard seems to add confusion to the process. Question 14 - The Commission is looking to have perodic drills of simulated load shedding performed and not just tests. The interpretation of "test" is open to each entity and just running an engineering computer simulation does not meet the directive.

Organization	Question 14 Comment
CECD	Question 14. The directive specifically states that there should be periodic drills of simulated load shedding" and CECD recommends R9 be modified to include testing through simulation of the applicable load shedding plan."
United Illuminating Company	R3 should specify it is manual load shedding or operator initiated loadhedding, so as not to be confused with ufls, uvls, or sps. R8 will require an interpretation of the word "simulation". Is a simulation having a single operator on a SCADA development system initiate a simulation, or a table top, or a planning study showing that load can be dropped?R9 will require clarification on whether this is a single test coordinated with all entities participating at the same time on an area basis. R9 item 2 states personnel deployment shall be included, but not every entity requires to dispatch personnel to deploy manual load shed. The phrase " as required by the manual load shed plan" should be added.
Oklahoma Municipal Power Authority	There are two versions of EOP-003 currently posted for ballot and they are in conflict with one another. Recommend moving UFLS and UVLS to the PRC standards and only addressing manual load shedding in this standard.Define "tests". Would prefer the language directly from the Commission which stated "periodic drills of simulated load shedding". We find this language less ambiguous.
PacifiCorp	This needs to be coordinating with PRC-006-01 which is also out for comments. The requirements under R2 is already part of requirements under PRC-007 (new PRC-006-01) and PRC-010. The requirements under R4, R7 and R8 are part of requirements under PRC-007 (new PRC-006-01) . EOP-003 load shedding should be limited to manual load dropping, automatic load shedding occurs based on system conditions without operator interventions.Suggest voting NO on EOP-003.
IESO	We agree that changes to Requirement R3 address the directive in Paragraph 601, but disagree with the proposed addition of R8 and R9 to address Paragraph 603. Also, we have a coordination concern which we will raise after address the concerns with changes to meet the directive in Para. 603. Paragraph 603 of the directives ask for including requirement for periodic drills of simulated load shedding. The wording in R8 asks for testing the load shedding plan through simulation. There was already a dispute on the interpretation of "simulation" (in a recently posted interpretation), which may be interpreted as using simulator or computer simulation program. The directive simply requires a "drill" which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation. Requirement R8 as written goes outside of the scope of the directive. On the other hand, R8 should include testing the readiness and functionality of procedures for system operators as well as distribution personnel and LSEs as per Paragraphs 596 and 597 respectively.Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive. Further, which entities need to participate in the testing of the plan and the required testing details need much more time and industry discussion to

Organization	Question 14 Comment
	develop, and hence should be developed through the normal process not through this much abbreviated process. In addition, the meaning of the term “personnel deployment drills” in a requirement that asks for testing of the load shedding plan. It is more appropriate to clearly stipulate the intent or expected outcome of the drill rather than stipulating a term that is subject to different interpretation. It follows that we do not agree with the VSLs for this Requirement. Furthermore, Section 4 of this standard should also include Load Serving Entity and Distribution Provider to be consistent with this requirement.We also have a coordination concern with Project 2007-01 that is currently underway. We have a coordination concern with Project 2010-12 that is currently underway. Project 2010-12 on EOP-003-2 standard, whose latest draft has been posted for balloting and comment, revised EOP-003-2 with the intent to address two directives (601 & 603) in FERC Order 693. If the EOP-003-2 is approved, it will render the version being used for making changes to address the UFLS reference redundancy invalid in EOP-003-1 standard. If the ballot on EOP-003-2 fails, the work to address the directives of FERC Order 693 should be assigned to the Project 2007-01 SDT for inclusion in the next draft. Further, there should not be two versions of the same standard posted for balloting at the same time. We suggest that changes to EOP-003 to address the directives in Para. 601 and 603 be withheld until after the Board adopts the revised PRC-006-1 and EOP-003-1 if they receive ballot approval. If they fail, such work should be assigned to the Project 2007-01 SDT for inclusion in the next draft.
Midwest ISO Standards Collaborators	We disagree with the changes to address the directives in paragraph 601. No where does the directive require changes to be made. It only requires consideration of changes. How was this consideration made? Our understanding is that no drafting team was ever convened to discuss these changes. Thus, on this merit alone, the changes should be removed to be considered by a drafting team. Furthermore, the UFLS drafting team has already proposed changes to EOP-003 that are not coordinated with these changes to remove UFLS completely from this standard into of PRC-006. That set of changes to those standards will be balloted simultaneously with these changes based on the dates on NERC’s website. Coordinating load shedding plans with regional entities does not make any sense in today’s environment and is a vestige of the pre-enforcement area. The regional entities have no operating responsibilities and all the legal authority they need to review/request a registered entity’s load shedding plan. We are not convinced that the load shedding should be coordinated with the RC. Clearly, the RC should be made aware of load shedding plans and capabilities. Any coordination, however, would be of the automatic load shedding plans and should probably occur through the PC. That is precisely what the UFLS project is proposing that will be balloted simultaneously with this set of changes. Adding sub-requirements R3.1 through R3.4 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.

Organization	Question 14 Comment
	We believe R8 and R9 miss the entire point of the directive. The directive appears to be focused on exercising the load shedding plans without actually shedding load. Specifically, the Commissions states “periodic drills of simulated load shedding”. We believe the Commission did not include “simulated” for the purpose of simulating load shedding in a power flow or dynamics study for instance. If they had intended this, the requirement would have applied to the PC or TP. Rather, we believe the Commission used the word “simulated” before load shed to make it clear they did not intend for actual load to be shed during the drills. Further support for this position can be gathered by reviewing the Commissions directives and understanding of the UFLS standards in Order 693. Furthermore, we believe R8 and R9 should be written and addressed by a standards drafting team. These are significant issues and testing of load shedding plans is no small task. Because it will require the coordination of multiple registered entities, only a standards drafting team with the appropriate participation would be in a position to assess the appropriate requirement here and how often the tests should occur. Otherwise, we could end up with a reduction in reliability with actual load being shed from failure to properly coordinate tests or to understand that they are tests being conducted to comply with NERC standards.

15. Do you believe the changes made in response to the directive(s) contained in Paragraph 612 of Order No. 693 are both valid and address the directive(s)?

612	APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.	EOP-004-2	Modified Section B Requirement R2 and added Requirement R3. Added VSL for R3.

Organization	Question 15
Ameren	No
American Electric Power	No
CECD	No
Central Lincoln	No
Consumers Energy Company	No
Dynegy Inc.	No
E.ON U.S.	No
ERCOT ISO	No
Georgia System Operations Corporation	No
Illinois Municipal Electric Agency	No
Indiana Municipal Power Agency	No

Organization	Question 15
Kansas City Power & Light	No
National Grid	No
NERC Standards Review Subcommittee	No
Northeast Power Coordinating Council	No
Santee Cooper	No
Southern Company Transmission	No
Xcel Energy	No
Arizona Public Service Company	Yes
Dominion	Yes
Entergy Services	Yes
Florida Municipal Power Agency	Yes
IESO	Yes
Midwest ISO Standards Collaborators	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SERC OC Standards Review Group	Yes

Organization	Question 15
Springfield Utility Board	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

16. Do you believe the changes made in response to the directive(s) contained in Paragraph 615 of Order No. 693 are both valid and address the directive(s)?

615	The Commission declines to address Xcel's concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process. 608. Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations. Further, Xcel states that the requirement in Requirement R3.4 for a final report within 60 days may not be feasible given the current WECC process, which among other things, requires the creation of a group to prepare the report and a 30-day posting of a draft report before it becomes final. Xcel also states that if the ultimate purpose of the report is to provide information to avoid a recurrence of a system disturbance, then the Reliability Standard should be revised to require the distribution of the report to similarly situated entities.	EOP-004-2	Addressed definition of "Reportable Event" by adding reference to Attachment 1 in Section B Requirement R4. NERC concurs with FERC that Xcel's concerns regarding the WECC process should be handled through a request for a Variance. With regard to distribution of reports, NERC currently addresses this as the ERO.

Organization	Yes or No
Xcel Energy	No
Dynegy Inc.	No
Ameren	No
Northeast Power Coordinating Council	No
E.ON U.S.	No
Florida Municipal Power Agency	No
National Grid	No
Southern Company Transmission	No

Organization	Yes or No
American Electric Power	No
Oklahoma Municipal Power Authority	No
CECD	No
US Bureau of Reclamation	No
United Illuminating Company	No
Midwest ISO Standards Collaborators	No
Arizona Public Service Company	Yes
Dominion	Yes
Entergy Services	Yes
IESO	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SERC OC Standards Review Group	Yes
Springfield Utility Board	Yes
NERC Standards Review Subcommittee	Yes
Georgia System Operations Corporation	Yes
Consumers Energy Company	Yes

Organization	Yes or No
Kansas City Power & Light	Yes
Illinois Municipal Electric Agency	Yes
Santee Cooper	Yes
Western Electricity Coordinating Council	Yes

Comments on the EOP-004 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P612 and P615 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Question 16 Comment
IRC Standards Review Committee	Paragraph 612Taken in isolation the proposed change to R2 is appropriate.In the context of the entire requirement, the proposed changes to R2 and R3 are vague as written. The requirements mandate “prompt analysis”. FERC has requested NERC to avoid that kind of ambiguous phrase.The sub requirement R3.1 emasculates the main requirement by introducing “at a minimum”. From the FERC directive, it seems that only the sub requirement is needed and the main requirement should be deleted. Paragraph 615The proposed change to the definition of “Reportable Event” is in direct competition with the Event Analysis Working Group’s initiative to define Event Categories. That initiative is posted for comments.
ERCOT ISO	Q15 - The R3 proposed language is not required by the directive. The directive also does not require adding the Distribution Provider. The R2 language that exists covers the directive. The proposed sub-requirement is unnecessary because it is implied in the existing R2 language.
Indiana Municipal Power Agency	Question 15 - It is not clear if the entities in requirement 3 have to analyze just the BES disturbances within their own system or facilities, or if these entities have to include analysis of BES disturbances outside of their system and the affect of essentially all BES disturbances on their system or facilities. It is also not clear how these entities in requirement 3 will be made aware of such BES disturbances, especially BES disturbances outside of their system or facilities (if applicable). Question 16 - Abstain. IMPA is not sure if the Xcel concern has been addressed and cleared up entirely.
Central Lincoln	The requirement to provide the information to the Reliability Coordinator is not valid in the West, where the WECC RC has stated they do not want to deal with every registered entity. http://www.bpa.gov/corporate/business/reliability/Docs/2007/PNSC_RE_Data_Letter_2_070723.pdf. This policy has not changed with WECC as the RC.
Dynegy Inc.	#15 - Since Requirement R3 was modified and Requirement R3.1 was created to capture the responsibility of the GOP and LSE, Requirement R4 should also be modified by deleting the GOP and LSE from this Requirement R4 since the responsibility is now covered

Organization	Question 16 Comment
	in in Requirement R.1 Also, R3.1 should be revised so the responsible entity only includes information to the RC, BA, or TOP upon request. #16 - Attachment 1 was already part of the Standard thus just referencing Attachment 1 does not address Xcel's request.
Ameren	(a) R3 - nalyze disturbance on GOP system is unclear or vauge. Drafting team should describe what is expected. (b) R3.1 - "analyze performance of their equipment" is vauge. Drafting team should describe what is expected or delete the requirement. (c) A.5. Effective date - Most entities revise procedures on an annual basis. having an effective date that is less than a year away might result incremental, hastily developed procedures. If the effective date was the first day of the first calendar year after approval, it is likely no extra reviews/update would be necessary.
Northeast Power Coordinating Council	1. There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. 2. These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. 3. The RC and BA, responsible for analysis, most likely do not own much in the way of systems or facilities except for back-up facilities. The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 4. The new standard language in R3 and 3.1 suggests that any disturbance originating from outside of the applicable Registered Entity will have to be reported and there are no means for how the reporting is to be handled. 5. Why wasn't DP added to R4?
E.ON U.S.	In paragraph 612, FERC says to “consider the concern...in future modification”, not to actually change requirements. The adding of requirements and/or sub-requirements is therefore unnecessary to meet the directive.The performance of GO, DP or LSE equipment may not be required to analyze BES disturbances. Information should be provided only if it is requested, or if the GO, DP or LSE BES equipment malfunctioned. Simply requiring GO,DP or LSEs to in all instances provide information on their equipment performance does not improve reliability and adds unnecessary administrative and compliance obligations. In paragraph 615, FERC says to “consider the comments...in future modification”, not to actually change requirements. The adding of requirements and/or sub-requirements is therefore unnecessary to meet the directive.It is unclear how the insertion in R4 clarifies the definition of a reportable “event” as the standard references a reportable “incident.”
Florida Municipal Power Agency	In Paragraph 615, the changes made to the standard do not address the concern: "Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is

Organization	Question 16 Comment
	for each entity that has reporting obligations." Attachment 1 should be modified to define which Functional Entity needs to report which reportable event. It is still quite ambiguous who has to report what. For instance, a Distribution Provider would certainly not have to report an islanding event, yet, it is possible to interpret it that way.
National Grid	o There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. o These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. o The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. o There is inconsistency in requirements R3 and R4 with respect to “Distribution Provider”. R3 includes DP while R4 does not. National Grid suggests including Distribution Provider in R4. o Who is responsible for reporting when DP is analyzing the disturbances? National Grid suggests that DP should be listed in Attachment 1.
Southern Company Transmission	Paragraph 612 - Suggest removing the ‘At a minimum’ phrasing at the beginning of R3.1 as it does not add any clarity. We don’t believe the VSL being based on percentages is the best approach. The number of reportable events will likely be small. Instead of trying to construct one VSL, the VSLs for the entire standard should be undertaken at once. There should be a concern that generator operators, DP’s and LSEs may be unable to promptly analyze BES disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. Paragraph 615 - Not low hanging fruit.
American Electric Power	Paragraph 612There appears to be no benefit of having R3 and R3.1 as separate requirements. AEP suggests the two requirements be combined into one requirement as follows, “R3. Each Generator Operator, Distribution Provider, and Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities and provide this information to its associated Reliability Coordinator, Balancing Authority, and Transmission Operator.” Paragraph 615R4 needs to include the Distribution Provider since it was added to R3. The VSL for the proposed R3 is not consistent in severity with the existing VSL for R2. Under the current standard, each Generator Operator and Load Serving Entity is required to promptly analyze BES disturbances per R2 and its associated VSL. The proposed

Organization	Question 16 Comment
	standard moves the GOP and LSE requirements to a new requirement, R3. A VSL was established for R3, but the VSL for R2 was not revised. Per the proposed standard, failure of the Generator Operator to promptly analyze greater than 15% of its disturbances on the BES would result in a Severe VSL. However, using the existing R2 VSL, a Transmission Operator who fails to promptly review 1% to 25% of its disturbances on the BES would only be subjected to a Moderate VSL. The VSLs should be revised to allow for consistency between the R2 and R3 VSLs, and correspond with what has already been established for the TOP. Additionally the VSL for R2 in the current standard should be revised to remove reference to the Generator Operator. The last sentence of Measures M2 and M3 each need to be revised to reference Requirements 4.1 and 4.3, respectively.
Oklahoma Municipal Power Authority	Paragraph 615: Attachment 1 should be revised to clarify which Functional Entities are responsible for each type of reportable event.
CECD	Question 1: APPA's concerns appear to be with the inability to perform an analysis of a disturbance that originated outside of their system and with coordination between affected registered entities. The standard already specified that the registered entity must only perform an analysis of disturbances on "its system or facilities" so no modifications were required to address this issue. The second issue identified by APPA seems to be the coordination between affected parties. The proposed language in R3.1 partially addresses this issue by requiring coordination (information sharing) by the GOP, DP and LSE with their associated RC, BA , and TOP, however the RC, BA and TOP should also be required to share information with impacted entities. Question 2: If the intent of including the reference to Attachment 1 in R4 was to assist in defining a Reportable Event the parenthesis should be directly after the phrase "reportable incident" and "reportable incident" should be changed to "Reportable Event".
US Bureau of Reclamation	The generator operators in WECC provide disturbance reports to WECC. Thenew requirement provides the information to TOP, BA, and RC. This standardrequires far too many reports. Reports are sent to WECC, NERC, DOE and nowthe TOP and BA. It is not clear what benefit will be derived by this redundantrequirement. The requirement should be limited to analyzing the events andproviding reports upon request. WECC already has a disturbance reporting andanalysis process to ensure BES issues are addressed. In addition the entitiesmust analyze protection system operations in PRC-004.It is interesting that the COmmission continues to ensure unilateralcommunication among the entities by not requiring TOP and BA to share theirdisturbance reports with the GOP, DP, and LSE's.
United Illuminating Company	United Illuminating does not believe the VSL is properly descriptive. It lists the severity level based on a percentage of events not analyzed. What is the time period being considered? In a calendar year, in a three year audit period?
Midwest ISO Standards Collaborators	We suggest the parenthesis within the requirement should be removed from around the reference to the attachment. We don't believe that the changes address Xcel's concern expressed in the directive. We believe Xcel wanted more details for the specific functional entities. Furthermore, the directive did not state that the Commission believed that Xcel's concerns regarding the WECC process should

Organization	Question 16 Comment
	be handled through a variance as stated in NERC's comments. As a result, we do not believe the directives in paragraph 615 are fully addressed. Adding sub-requirement 3.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
NERC Standards Review Subcommittee	#15. The word "promptly" is used within R2 and R3 but not R3.1. Recommend that the word "promptly" be deleted from these requirements. During any system disturbance the RC, BA or TOP will be focusing on mitigating the disturbance, then reporting of the disturbance (as outlined in the standard) and then start to investigate the cause of the disturbance. When promptly is used and entity may investigate prior to reporting which may lead to a non compliance situation.
Georgia System Operations Corporation	15) In EOP-004 R3.1 the introductory words "At a minimum" imply that more action than stated might be needed to be compliant but the requirement does not elaborate on what additional steps might be required. "At a minimum" adds nothing to the requirement except ambiguity and should be deleted. FERC never said that we have to take the exact wording from their order and insert it into the standard. The ambiguity is compounded by structuring R3 as a requirement and sub requirement. We recommend deleting R3.1 and rewriting R3 as follows: Each Generator Operator, Distribution Provider, and Load Serving Entity shall promptly analyze the performance of its equipment in reacting to a Bulk Electric System disturbance on its system or facilities and provide the results of its analysis to its Reliability Coordinator, Balancing Authority, and Transmission Operator. Also, as a general statement this standard refers to Regional Reliability Organization instead of Regional Entity. The Measures refer to Requirements R3.1 and R3.3. We believe they should refer to R4.1 and R4.3 now.
Consumers Energy Company	Comments: It is unclear as to what constitutes a disturbance. Does a disturbance, in the context of R2 and R3, constitutes a simple fault that is observable on the BES but normally cleared, or is it more limited. As written, these requirements could be interpreted to trigger thousands of "disturbance investigations" annually, the vast majority of which have no impact. Additionally, Attachment 2 (unchanged in this draft) purports to summarize OE-417 reporting requirements, but has a number of inaccuracies related to Attachment 2 timeliness requirements as compared to OE-417 reporting requirements (many of the elements with 1-hour reporting on Attachment 2 have 6-hour reporting on OE-417). It must be clarified whether Attachment 2 defines NERC requirements, or whether, for events described on OE-417, that OE-417 timeliness requirements govern. It should also be considered, relative to 1-hour reporting on Attachment 2, that, in the initial hour or two of an actual event, operating

Organization	Question 16 Comment
	personnel will be fully engaged in determining the scope of the event and in addressing immediate operating concerns, and that they would be distracted from immediate reliability-related activities to prepare and file a report. Relative to R3 and the related VSL, “promptly” is a very subjective term, and is likely to lead to contention when evaluating compliance. Finally, there is unresolved duplication between this standard (Attachment 2, Incident No 5) and CIP-001 regarding sabotage incidents, and Attachment 2, Incident No 6 and CIP-008 regarding cyber incidents. We feel that the changes in this draft do not offer any improvement in the quality of this standard, and that, given the major problems with EOP-004-1, that the entire standard must be re-written, given due consideration to the inconsistencies with OE-417 and the inadvertent duplication with CIP-001 and CIP-006. Please provide your opinion regarding the Paragraph 612 VRF and VSLs: Opposed Comments: It is unclear as to what constitutes a disturbance. Does a disturbance, in the context of R2 and R3, constitutes a simple fault that is observable on the BES but normally cleared, or is it more limited. As written, these requirements could be interpreted to trigger thousands of “disturbance investigations” annually, the vast majority of which have no impact. Additionally, Attachment 2 (unchanged in this draft) purports to summarize OE-417 reporting requirements, but has a number of inaccuracies related to Attachment 2 timeliness requirements as compared to OE-417 reporting requirements (many of the elements with 1-hour reporting on Attachment 2 have 6-hour reporting on OE-417). It must be clarified whether Attachment 2 defines NERC requirements, or whether, for events described on OE-417, that OE-417 timeliness requirements govern. It should also be considered, relative to 1-hour reporting on Attachment 2, that, in the initial hour or two of an actual event, operating personnel will be fully engaged in determining the scope of the event and in addressing immediate operating concerns, and that they would be distracted from immediate reliability-related activities to prepare and file a report. Relative to R3 and the related VSL, “promptly” is a very subjective term, and is likely to lead to contention when evaluating compliance. Finally, there is unresolved duplication between this standard (Attachment 2, Incident No 5) and CIP-001 regarding sabotage incidents, and Attachment 2, Incident No 6 and CIP-008 regarding cyber incidents. We feel that the changes in this draft do not offer any improvement in the quality of this standard, and that, given the major problems with EOP-004-1, that the entire standard must be re-written, given due consideration to the inconsistencies with OE-417 and the inadvertent duplication with CIP-001 and CIP-006.
Kansas City Power & Light	Directive 612:Do not believe the proposed changes addresses the concerns of APPA as recognized by the Commission. The proposed requirements direct the Generator Operators and Load Serving Entities to “promptly analyze Bulk Electric System disturbances on its system or facilities” in R3 which APPA has a direct concern. Recommend modifying the requirement R3 and sub-requirement R3.1 to state that Generator Operators and Load Serving Entities provide data available from installed data recording systems, if they exist, upon request of other TOP’s or BA’s.
Illinois Municipal Electric Agency	It is not clear in R3.1 how an entity is to "provide". Why not just add DP to R4 as one of the reporting entities, and add RC, BA, and TOP to R4 as also receiving the preliminary written report?
Santee Cooper	Paragraph 612 -The proposed changes do not appear to address the Commission’s directive. We suggest a new requirement should be “Following a disturbance and at the request of a RC, BA or TOP, a GO, DP or LSE shall promptly analyze the performance of their

Organization	Question 16 Comment
	equipment and provide all requested information necessary to analyze BES disturbances."
Western Electricity Coordinating Council	Requirement R2 requires applicable entities to promptly analyze Bulk Electric System disturbances. There is no definition for the term promptly, and therefore the Requirement is vague. Promply needs to be clarified, considereing differnet time frames for differning types of events.

17. Do you believe the changes made in response to the directive(s) contained in Paragraph 693 of Order No. 693 are both valid and address the directive(s)?

693	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.	FAC-002-1	Modified Section B Requirement R1.4

Organization	Yes or No
E.ON U.S.	No
Xcel Energy	No
Consumers Energy Company	No
Kansas City Power & Light	No
ERCOT ISO	No
US Bureau of Reclamation	No
Midwest ISO Standards Collaborators	No
Ameren	Yes
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Dominion	Yes

Organization	Yes or No
Dynegy Inc.	Yes
Entergy Services	Yes
Florida Municipal Power Agency	Yes
IESO	Yes
Illinois Municipal Electric Agency	Yes
Indiana Municipal Power Agency	Yes
National Grid	Yes
NERC Standards Review Subcommittee	Yes
Northeast Power Coordinating Council	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
SDG&E	Yes
SERC OC Standards Review Group	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

Organization	Yes or No
Georgia System Operations Corporation	Yes
Southern Company Transmission	Yes

Comments on the FAC-002 Standard Changes

Summary Consideration:

The majority of commenters agree with the proposed changes.

Some commenters expressed a concern that by making a reference to the TPL standards, the Responsible Entities for the FAC-002 standard will be subject to having to also comply with the referenced TPL standards. The Response Team holds the view that this already exists within the original language of the standard via its reference to TPL-001. The Response Team does not think that in general, referencing another standard will subject the entities listed in the Applicability Section to be also held responsible for complying with the referenced standard. We encourage stakeholders to work to improve this standard in its next version.

Some commenters suggest removing the wording “under both normal and contingency conditions” from Requirement R1.4. The Response Team has not adopted the suggested change since the proposed wording in R1.4 adopts the same wording indicated in the directive. We do not see the added value by adopting the commenters’ proposed alternative wording. Nonetheless, we thank the commenters for their suggestion.

Organization	Question 17 Comment
IRC Standards Review Committee	Paragraph 693Taken in isolation the proposed change to R2 is appropriate.In the context of the entire requirement, the proposed change raises an issue that make this seemingly trivial request more complex than the requestor makes it out to be. o The proposed change is a change to a sub requirement to R1. However, R1 is not well designed as a mandatory standard. R1 includes multiple applicable entities, and requires that those entities all “coordinate and cooperate”. The latter terms are not defined, not measured and confusing as it applies to compliance. Response: This scope of this project is to implement changes as indicated in the directives. The project does not include improving the quality of the entire standard. However, your comment will be retained for future consideration when this standard is due for revision.
Consumers Energy Company	Comments: Of the six applicable entities on FAC-002, only two are applicable entities under the TPL standards (Transmission Planner and Planning Authority/Coordinator, depending on the Functional Model terminology). The reference to the TPL standards in R1.4, which addresses ONLY the other four entities, makes those entities indirectly subject to the TPL standards, which are irrelevant to those entities. Response: The Response Team does not share your view that the Responsible Entities for the FAC-002 standard will be subject to having to also comply with the referenced TPL standards. The Response Team does not think that in general, referencing another standard will subject the entities listed in the Applicability Section to be also held responsible for complying with the referenced standard. We encourage the commenter to work to improve this standard in its next version.
Kansas City Power & Light	Directive 693:The Violation Severity Levels for R1.4 do not reflect the additional references to Standards TPL-002-0 and TPL-003-0 as

Organization	Question 17 Comment
	included in the proposed change for R1.4. Response: The VSLs for R1 of FAC-002 do not make specific reference to the details contained in each of the subrequirements. We do not see any inconsistency that warrants the need for changing the VSLs.
ERCOT ISO	Q17 - The proposed language certainly addresses the directive, but all that was needed was to reference TPL-002 and TPL-003. ERCOT ISO suggests the following wording for R1.4: “Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.” Response: The wording in the draft standard adopts the same wording indicated in the directive. We do not see the added value by adopting your proposed alternative wording. But we thank the commenter for the suggestion.
US Bureau of Reclamation	The requirement cites TPL-001 through 003 which do not apply to GO's. Themodification makes matters worse in that the GO is now required to analyzesystem performance under contigency conditions. This is normally performed bythe TP. Response: This obligation to conduct studies exists in the current standard. The proposed changes serve to clarify an aspect of the scope of studies only. We do not see this change has any material impact on the individual Responsible Entities’ obligations.
Midwest ISO Standards Collaborators	We believe “under normal and emergency contingency conditions” should be struck from the additions. TPL-001, TPL-002 and TPL-003 already identify normal and emergency conditions through the Table C requirements. We believe the clause only adds confusion. Furthermore, the Commission did not request the clause to be added but requested the reference to TPL-001, TPL-002 and TPL-003 to be added “to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.” Response: The wording in the draft standard adopts the same wording indicated in the directive. We do not see the added value by adopting your proposed alternative wording. But we thank the commenter for the suggestion.
Georgia System Operations Corporation	None.
Southern Company Transmission	Paragraph 693 - The Commission did not request the clause to be added but only requested the reference to TPL-001, TPL-002 and TPL-003 to be added “to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.” Response: The wording in the draft standard adopts the same wording indicated in the directive. We do not see the added value by adopting your proposed alternative wording. But we thank the commenter for the suggestion.

18. Do you believe the changes made in response to the directive(s) contained in Paragraph 1249 of Order No. 693 are both valid and address the directive(s)?

1249	The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.	MOD-017-1	Modified Section B Requirement R1.1, R1.2. Modified VSLs for R1.

Organization	Question 18
Ameren	No
American Electric Power	No
Arizona Public Service Company	No
Central Lincoln	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No

Organization	Question 18
Indiana Municipal Power Agency	No
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
Pepco Holdings, Inc. - Affiliates	No
Santee Cooper	No
SDG&E	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Western Electricity Coordinating Council	No
CECD	Yes
Consumers Energy Company	Yes
Florida Municipal Power Agency	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes

Organization	Question 18
Springfield Utility Board	Yes
United Illuminating Company	Yes
Xcel Energy	Yes

19. Do you believe the changes made in response to the directive(s) contained in Paragraph 1250 of Order No. 693 are both valid and address the directive(s)?

1250	We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.	MOD-017-1	Modified Section B Requirement R1.1, R1.2. Modified VSLs for R1.

Organization	Question 19
Ameren	No
American Electric Power	No
Arizona Public Service Company	No
Central Lincoln	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No

Organization	Question 19
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
Santee Cooper	No
SDG&E	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Western Electricity Coordinating Council	No
Xcel Energy	No
CECD	Yes
Consumers Energy Company	Yes
Florida Municipal Power Agency	Yes
Indiana Municipal Power Agency	Yes
Kansas City Power & Light	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes

Organization	Question 19
Pepco Holdings, Inc. - Affiliates	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes

20. Do you believe the changes made in response to the directive(s) contained in Paragraph 1251 of Order No. 693 are both valid and address the directive(s)?

1251	The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.	MOD-017-1	Added Section B Requirement R1.5. Modified VSLs for R1.

Organization	Question 20
Ameren	No
American Electric Power	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Florida Municipal Power Agency	No
Georgia System Operations Corporation	No
IESO	No
Illinois Municipal Electric Agency	No

Organization	Question 20
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No
Northeast Power Coordinating Council	No
Oklahoma Muncipal Power Authority	No
Santee Cooper	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Xcel Energy	No
Arizona Public Service Company	Yes
CECD	Yes
Indiana Municipal Power Agency	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SDG&E	Yes
Springfield Utility Board	Yes

Organization	Question 20
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

21. Do you believe the changes made in response to the directive(s) contained in Paragraph 1252 of Order No. 693 are both valid and address the directive(s)?

1252	The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.	MOD-017-1	Added Section B Requirement R2. Added Measure M2 and VSLs for R2.

Organization	Question 21
Ameren	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
ERCOT ISO	No
Georgia System Operations Corporation	No
IESO	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No

Organization	Question 21
NERC Standards Review Subcommittee	No
Northeast Power Coordinating Council	No
Santee Cooper	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
United Illuminating Company	No
Xcel Energy	No
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Florida Municipal Power Agency	Yes
Illinois Municipal Electric Agency	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
SDG&E	Yes
Springfield Utility Board	Yes

Organization	Question 21
Western Electricity Coordinating Council	Yes

22. Do you believe the changes made in response to the directive(s) contained in Paragraph 1255 of Order No. 693 are both valid and address the directive(s)?

1255	We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.	MOD-017-1	Added Section A 4.4 (Transmission Planner). Modified Section B Requirement R1 and R2. Modified Measure M1.

Organization	Yes or No
Xcel Energy	No
IESO	No
Santee Cooper	No
Ameren	No
Kansas City Power & Light	No
Florida Municipal Power Agency	No
National Grid	No
Oklahoma Municipal Power Authority	No
Dominion	No
Entergy Services	No
SERC OC Standards Review Group	No
Midwest ISO Standards Collaborators	No
Southern Company Transmission	No

Organization	Yes or No
CECD	Yes
Springfield Utility Board	Yes
NERC Standards Review Subcommittee	Yes
Northeast Power Coordinating Council	Yes
Georgia System Operations Corporation	Yes
Consumers Energy Company	Yes
Arizona Public Service Company	Yes
SDG&E	Yes
American Electric Power	Yes
ERCOT ISO	Yes
Indiana Municipal Power Agency	Yes
PacifiCorp	Yes
Western Electricity Coordinating Council	Yes
United Illuminating Company	Yes
Pepco Holdings, Inc. - Affiliates	Yes
E.ON U.S.	Yes

Comments on the MOD-017 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P1249, P1250, P1251, P1252, and P1255 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Question 22 Comment
Central Lincoln	For an entity that covers a diverse area, it is unclear where the temperature and humidity readings are to be taken, or if many (how many?) readings are to be averaged. And why does the entity that has a variation on temperature but not humidity, still need to report humidity?
IRC Standards Review Committee	Paragraph 1249 & 1250The proposed change to add the clarification “for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year” does not support reliability for the following reasons: 1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to collect the information at that time 2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA’s varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the individual LSE loads has no meaning for Interconnection reliability.If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence. 3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities. 4. FERC’s claim that such weather information analysis can be useful does not recognize that there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research

Organization	Question 22 Comment
	but not a good reason to mandate data. 5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work. Paragraph 1251The proposed changes to R1.5 are confusing. It asks for “day-ahead”, monthly peak and annual peak demands which implies forecast data, yet the wording in parenthesis implies after the fact error assessment. Further, it is unclear what “biasing of each load forecast” means. In fact, the entire MOD-017 is confusing as it mixes forecast data with actual data without a clear delineation between the two sets. The standard itself needs reworking to add clarity. The addition of R1.5 makes the standard even more confusing. We suggest this change be pulled off from this round of revision. Paragraph 1252 & 1255There are several issues with the accuracy proposal: 1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact. 3. The requirement obligates each entity to supply this data to “every other” LSE, PA and RP. This is both unjustified and impractical. 4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other entities have no responsibility for such data. 5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous “normal” hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2.Finally, since this and the other MOD standards included in this project are predicated upon MOD-016-1 which has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Illinois Municipal Electric Agency	What will this additional data reporting accomplish? Has a problem ben identified with the current MOD-017 reporting that needs to be resolved? If so, it has not been communicated. These proposed revisions need further vetting to adequately assess the need and the impact on entity resources, particularly small entity resources.

Organization	Question 22 Comment
IESO	(1) We do not agree with the changes to R1.2, in particular the second sentence which asks for weather data which is redundant with that already provided in R1.1. (2) Specific to the proposed changes to address the directive in Paragraph 1251, R1.5 is confusing. It asks for "day-ahead", monthly peak and annual peak demands which implies forecast data, yet the wording in parenthesis implies after the fact error assessment. Further, it is unclear what "biasing of each load forecast" means. Is it operator adjustments? If so, isn't forecaster/operator expertise part of the forecasting process? Forecasting (especially long term) is not just a mechanical exercise but requires "value-added" actions by the forecaster. Biasing is not a defined term. In fact, the entire MOD-017 is confusing as it mixes forecast data with actual data without a clear delineation between the two sets. The standard itself needs reworking to add clarity. The addition of R1.5 makes the standard even more confusing. We suggest this change be pulled off from this round of revision. Further, day-ahead hourly for each hour is not clear. This could represent a large number of forecasts (if multiple day ahead forecasts are made). (3) Specific to the proposed changes to address the directive in Paragraph 1252, we question the basis for the 10% error if used as a threshold for R2. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Further, the 10% threshold seems loose. Is it in effect saying that the responsible entity should review it forecasting process on an annual basis? Sometimes an error of 10% is totally explainable and should not warrant a change in forecast methodology (this is especially true for long term forecasts where weather is uncertain). It is prudent to review the methodology but to change it for changes sake is not.In addition, the word "load" should be Capitalized throughout in R2 and M2.
Santee Cooper	All Paragraphs - We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Ameren	All referenced requirements need to explicitely address DSM, or the effect of DSM, on the forecast. The drafting team should clearly define how DSM should be considered, that is as an interruptible load or as a resource.
Kansas City Power & Light	Directives 1251, 1252, and 1255:Do not agree with the concept of developing an indices that indicates the "accuracy, error and bias" between forecasted hourly loads and actual hourly loads as indicated by proposed additions of requirements R1.5 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to "normalize" actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different "latent heat" or "latent cold" build-ups. Poor indications of load accuracy are of no value and can be misleading.In addition, techniques developed by load forecasting groups to "compare" actual data to forecasted data will be

Organization	Question 22 Comment
	subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Florida Municipal Power Agency	In Paragraph 1251, load forecasting in the planning horizon is performed using a different method and a different purpose than load forecasting in the operating horizon. The MOD standards to not require a Day-ahead hourly forecast, the operating horizon standards do. Hence, Day-ahead hourly load forecasts should not be included in MOD-017 and R1.5 should be modified to remove Day-ahead Hourly for each hour since only monthly and annual peak loads are being forecasted in R1.3 as part of the planning horizon efforts.In Paragraph 1255, Transmission Planners should not be responsible for load forecasting and hence should not be applicable to this standard. Transmission Planners simply gather the load forecasts of the entities responsible for load forecasting within their planning area. In essence, a Transmission Planner will be dependent on the compliance of the entities within its planning area to remain compliant. If that is the case, then, there should be multiple requirements making entities within the planning area report load forecasts to the Transmission Planner before the Transmission Planner is enabled to report a load forecast to the region. This additional layer of administrative burden makes no sense. If Transmission Planners develop different, independent load forecasts, which ones will be used in the regional analyses? Those provided by the TPs, or the aggregate of those provided by other entities within the TPs planning area? The FERC directive can probably be addressed through a requirement of the Region to break out the regional load forecast by each Transmission Planning area.
National Grid	o In requirement R1.1, the location of the reading for coincident hourly temperature and humidity is not clear. Also, in National Grid, the record keeping is done on aggregate basis and not on daily basis. The data is taken from weather services and it is not an automatic process of data collection. o In Requirement 1.5, is the load on a system basis or on a substation/bus basis? What is meant by “biasing of each load forecast”? Is this applicable to Demand Response? Also, “day-ahead hourly” does not add any value from a Planning perspective since it is a market/operations issue. o With respect to Requirement R2.0 - Remove the wording in the parentheses. Also, delete it from the VSL. o National Grid believes that the Planning Authority has the authority to collect information and hence the information collection should be retained at the level of Planning Authority and not include Transmission Planner. o General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. o General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. o General comment - Each entity’s expertise should be relied upon to gather the appropriate weather information.
Oklahoma Municipal Power Authority	Paragraph 1251: Remove Day-ahead hourly forecasts from R1.5 to be consistent with the rest of the standard; specifically,

Organization	Question 22 Comment
	R1.3. Paragraph 1255: Transmission Planners should not be responsible for load forecasting. Load forecasting is completed by other entities and submitted to Transmission Planners.
Dominion	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. Some examples are cited below: 1. We do not agree that addition of the Transmission Planner, in and of itself, improves or enhances reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads "vary based on temperature and/or humidity" and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads "vary based on temperature and/or humidity" and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. 2. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models. 3. R2, as written, could decrease reliability by allowing a wider bandwidth before action iscurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. 4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
Entergy Services	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads "vary based on temperature and/or humidity" and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service

Organization	Question 22 Comment
	Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads "vary based on temperature and/or humidity" and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models.R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
SERC OC Standards Review Group	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads "vary based on temperature and/or humidity" and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners,Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads "vary based on temperature and/or humidity" and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models.- R2, as written, could decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or

Organization	Question 22 Comment
	enhance reliability.
Midwest ISO Standards Collaborators	While the proposed changes may meet directives in paragraph 1249 and 1250, we do not believe this represents the solution that is needed. For one, there is no clear or apparent use of the data being supplied. If the data is to gauge the accuracy of load forecast, FERC already directed the ERO to write other requirements to assess accuracy. Secondly, the requirement does not indicate what data is to be supplied. Is it the data that the entity uses for input into their load forecast model? Is it the data for every major city? Thirdly, each load forecast is highly dependent on the model being used. While some entities may use dozens of locations for weather input others may not. Thus, any effort to normalize load to weather will be dependent on the process/model that the ERO or the Region Entity is using. The data supplied may not match the needs of the ERO or Regional Entity. Because this information is so readily available, it only makes sense for the ERO and Regional Entities to gather the information from an appropriate commercial service to ensure the data meets their needs. We disagree with the proposed changes to address directives in paragraph 1251. While they may technically meet the directive because the wording from the directive was essentially inserted as a sub-requirement, we do not believe that the requirement is clear or represents the best solution. For instance, what is biasing in a load forecast? Additionally, the Commission did not state what load forecast error should be compared. For example, LSEs will have dozens of load forecasts for the same time period that are updated with newer weather information as the operating hour approaches. Why was Day-Ahead selected? Why not seven days ahead? 12 hours ahead, etc.? We believe this directive does not represent low-hanging fruit that can be addressed in an ad hoc manner such as this SAR. Further, because load forecasting is complicated process, we believe it is necessary to retain a group of load forecasting experts in a drafting team to address these directives appropriately so that meaningful requirements can be written. We disagree with R2 that is intended to address the directives in paragraph 1252 and 1255. An LSE is constantly updating and tuning their load forecast model and cannot tolerate a load forecast error anywhere close to 10%. If an LSE only reviewed their load forecast annually and adjusted the inputs if the error exceeded 10%, there are many days each year that the LSE would likely not serve load. This requirement represents a significant reduction in reliability. A group of load forecasting experts needs to be convened in a drafting team to address this directive. Adding sub-requirements R1.5 and modifying sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a

Organization	Question 22 Comment
	standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Southern Company Transmission	While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads "vary based on temperature and/or humidity" and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads "vary based on temperature and/or humidity" and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models.R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately. While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
NERC Standards Review Subcommittee	#21. R2 states that as an example, variation expressed in terms of error divided by actual demand is greater than 10%. The 10% threshold is not defined by FERC in its Order and request that a basis be given prior to supporting the proposed changes. Overall R2 does not enhance reliability of the BES. R2 states that the applicable entity annually reviews the previous year's load forecast for 10% variation and if necessary modify load forecast assumptions to improve accuracy. It is unclear if the improved assumptions are to be used for the previous year or the upcoming year? If for the upcoming year, than it must be clearly stated that the responsible entity is to apply last year assumptions to next year's forecast.
Northeast Power Coordinating Council	1. General comment - In the "NERC Comments" section, remove the "Section B" descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry.

Organization	Question 22 Comment
	3. General comment - Each entity's expertise should be relied upon to gather the appropriate weather information. 4. In Requirement R1.5 - What is meant by "biasing of each load forecast"? 5. With respect to Requirement R1.5 - Is this applicable to Demand Response? 6. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 7. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 8. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.
Georgia System Operations Corporation	18a) MOD-017 R1. It is not clear what temperature and humidity data to use. We believe this data collection would actually serve to confuse rather than enhance reliability. If the requirement remains, recommend removing the "if" clause and simply stating to supply temperature and humidity data. 18b) MOD-017 R2. It is not clear when an entity is required to modify its load forecast assumptions. The use of the abbreviation e.g. (which means "for example") implies that there are other situations which would require modification of the forecast assumptions, but we are given no guidance as to what they might be. The 10% seems to be an arbitrary value as well. Utilities, as good business practice, seek to have the best forecast possible and its inherent to their own interests to either improve their process or replace the model as needed. We recommend the requirement should be rewritten as follows:1 8c) The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall annually review its Load forecast process to improve accuracy as necessary. 18d) Otherwise, if there are other conditions that would require that assumptions be modified those conditions must be clearly stated in the standard. Entities have a right to a clear statement of what they are required to do and when they are required to do it. Sometimes assumptions are correct, and extreme conditions occur. It does not necessitate that your assumptions should change for the next year. 20) MOD-017 R1.5. It is not clear as written. At a minimum, we recommend removing the daily granularity for reporting of hourly load forecast error.21) The VSL's should remove the "e.g." language.
Consumers Energy Company	Changes for directives in Paragraph 1249: Approve Please provide your opinion regarding the Paragraph 1249 VSL changes: In Favor Changes for directives in Paragraph 1250: Approve Please provide your opinion regarding the Paragraph 1250 VSL changes: In Favor Changes for directives in Paragraph 1251:

Organization	Question 22 Comment
	Disapprove Comments: R1.5 includes a requirement for "Day-ahead Hourly . . . load Forecast accuracy . . .". This seems to exceed the focus of the Order, which is oriented toward planning. Additionally, the standard is not clear what is intended by "day-ahead" forecast. There often are multiple "day-ahead" forecasts, as weather forecasts change and current day load patterns emerge. Finally, the text appears to capitalize terms that are not defined in the Glossary.Please provide your opinion regarding the Paragraph 1251 VSL changes: In Favor Changes for directives in Paragraph 1252: Disapprove 44) Comments R2 (and therefore VSL 2) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.45) 32. Please provide your opinion regarding the Paragraph 1250 VRF and VSLs Opposed 46) Comments R2 (and therefore VSL 2) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
Arizona Public Service Company	For both Question 18 and 19, AZPS does not agree with how NERC has revised the standard to comply with Order 693. Our reading is that FERC is requesting temperature and humidity readings for the peak load, interpreted as Peak Day. The Standard as proposed is over-reaching as it requires weather data for each and every hour of every day (8760).
SDG&E	Paragraph 1249, Proposal is cumbersome and problematic in term of accurate regional weather normalization. Alternative approach: direct each entity to provide its own estimate of weather-normalized load (instead of providing raw data on hourly temperature and humidity). Paragraph 1250, Requirement 1.1 and 1.2; (Issue: ALCOA proposal). Suggested Reporting of weather data should not be required for entities whose entire load is not weather-sensitive.
American Electric Power	Paragraphs 1249 & 1250The proposed change in MOD-017 R1.1, “for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year” does not support reliability for the following reasons: 1. It is unclear what reliability objective is being served. If this data is for NERC to analyze and verify peak load data used by Registered Entities for operations, then the weather across Registered Entities varies too greatly to provide one set of coincident numbers and would provide little benefit. What reliability benefit would there be to add a requirement for sending information that will not be used? This would be an inefficient use of resources, which could instead be used for supporting other reliability objectives. 2. Whether or not the load data is sensitive to weather is a matter of importance for the local planners, but not for planners who

Organization	Question 22 Comment
	report wide-area assessments to NERC. 3. NERC through its Rules of Procedure has the ability to collect the information when necessary.Paragraph 1251With respect to MOD-017 R1.5, we do not see the benefit to include the day-ahead forecast accuracy to NERC and the Regional Entities.
ERCOT ISO	Q18 - The language does seem to address the directive, but is likely to be controversial as it goes directly to telling how to do something rather than what needs to be done to ensure reliability. This standard needs to be fully vetted with the industry through the standards development process in order to refine the requirements from the current language to properly address the directive. These changes cause ambiguity. Q19 - See Q18 comments immediately above. Q20 - The proposed language requires reporting, but it does not address the temperature and humidity variations. Again, this language gets into details of how to do something rather than what must be done. This change causes ambiguity.Q21 - The proposed language appears to address the directive, but ERCOT ISO disagrees with the added parenthetical language. Furthermore, ERCOT ISO disagrees with the phrase ‘if necessary’ because it introduces ambiguity.
Indiana Municipal Power Agency	Question 18 - The Commission is not requiring that the coincident hourly temperature and humidity data be recorded for the prior year (for each load hour, peak and off peak). It is IMPA's belief that the way this current requirement is written goes beyond teh Commission directive and is creating an undue burden on entities. IMPA does agree that collecting the day's temperature high and low temperature, along with the day's humidity (or just the peak period humidity), meets this directive and should be recorded for weather normalization of the peak load. The collecting of off-peak hourly weather data is not useful and is wasteful. Question 21 - The high VSL includes the for example wording "variation was greater than 10%". If this is truly for example only, it should be removed from the VSL which will eliminate teh influence of an example statement in the enforcement of the high VSL for requirement 2.
PacifiCorp	Request addition implementation time since this standard is not related to reliability improvements. These upgrades will require significant software and system changes and may require upgrades in technology to allow interactive communication with other utilities. R1.1 Current wording “For loads that vary based on temperature and/or humidity...” is vague-all of PAC loads could fall under this criteria. What kind of granularity is appropriate-entire BA???? R1.5 Internal comment-New language “Day-ahead Hourly, Monthly Peak hour...” hourly is significantly more detail than current processes.If the new language requires accuracy (“...expressed in terms of error divided by actual demand) as well as any biasing of each load forecast...”), will this have any impact on spot purchasing process? Rephrase the language as follows since we base our analysis on average daily temperature. For Loads that vary based on temperature and/or humidity,

Organization	Question 22 Comment
	temperature and humidity data for the prior year used to normalize demands.
Western Electricity Coordinating Council	Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 (redundant). An alternative to actually submitting the coincident hourly temperature and humidity data is to require the applicable entity to be able to demonstrate that they record and consider coincident hourly temperature and humidity data when developing forecasts.
United Illuminating Company	United illuminating agrees with the intent but has concerns with the requirement R2. The statement in parenthesis is unclear if NERC is establishing 10% as the allowable variation or not. It's inappropriate to use e.g in a VSL matrix.UI suggests that the entity developing the Load Forecast maintains a document describing the allowable variation and how it is calculated.The Standard requires two Load Forecasts a two year monthly (R1.3) and as requested a five to ten year forecast (R1.4). It is unclear which forecast is being addressed in R2.
Pepco Holdings, Inc. - Affiliates	While the changes address the directives, there is no real need for this kind of data beyond what is already used in planning. We fervently hope this is removed when the full standard is reviewed in the normal process.
E.ON U.S.	With respect to paragraphs 1249 & 1250, FERC directs submittal of temperature and humidity. The proposed revisions go beyond what is directed by FERC by adding temperature sensitive loads to the requirements. In paragraph 1251, FERC directive allows adjustment for temperature and humidity variations while the proposed revisions to R1.5 does not allow this adjustment. In addition, the term "biasing" is introduced, but is not discussed nor defined with respect to load forecasting. With respect to paragraph 1252, FERC did not specify how to correct forecasts. NERC should assemble a drafting team to develop reasonable criteria for correcting potential forecast error based on historic inaccuracies.â€ƒ

23. Do you believe the changes made in response to the directive(s) contained in Paragraph 1276 of Order No. 693 are both valid and address the directive(s)?

1276	The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	MOD-019-1	Modified Section B Requirement R1.

Organization	Question 23
Ameren	No
Arizona Public Service Company	No
Consumers Energy Company	No
Dominion	No
E.ON U.S.	No
Entergy Services	No
Florida Municipal Power Agency	No
Indiana Municipal Power Agency	No
Kansas City Power & Light	No
Midwest ISO Standards Collaborators	No
National Grid	No

Organization	Question 23
Northeast Power Coordinating Council	No
Oklahoma Muncipal Power Authority	No
Pepco Holdings, Inc. - Affiliates	No
Santee Cooper	No
SDG&E	No
SERC OC Standards Review Group	No
Southern Company Transmission	No
Springfield Utility Board	No
Xcel Energy	No
American Electric Power	Yes
CECD	Yes
ERCOT ISO	Yes
Georgia System Operations Corporation	Yes
IESO	Yes
Illinois Municipal Electric Agency	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes

Organization	Question 23
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes

24. Do you believe the changes made in response to the directive(s) contained in Paragraph 1277 of Order No. 693 are both valid and address the directive(s)?

1277	We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.	MOD-019-1	Added Section B Requirement R2. Added VSLs for R2.

Organization	Yes or No
Xcel Energy	No
NERC Standards Review Subcommittee	No
IESO	No
Ameren	No
Northeast Power Coordinating Council	No
Santee Cooper	No
Arizona Public Service Company	No
Consumers Energy Company	No
Kansas City Power & Light	No
E.ON U.S.	No
Florida Municipal Power Agency	No
SDG&E	No
Oklahoma Municipal Power Authority	No

Organization	Yes or No
Georgia System Operations Corporation	No
National Grid	No
Southern Company Transmission	No
SERC OC Standards Review Group	No
Dominion	No
ERCOT ISO	No
Indiana Municipal Power Agency	No
American Electric Power	No
Springfield Utility Board	No
United Illuminating Company	No
Midwest ISO Standards Collaborators	No
Entergy Services	No
CECD	Yes
Illinois Municipal Electric Agency	Yes
Western Electricity Coordinating Council	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes

Comments on the MOD-019 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P1276 and P1277 directives will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Yes or No	Question 24 Comment
IRC Standards Review Committee		Paragraph 1276Taken in isolation the general nature of the proposed change to R1 is appropriate.In the context of the details of the requirement, the proposed R1 changes raise issues regarding: the lack of clarity in definition of what DCLM is; what biases (see R1.2) it wants and who needs what information for reliability. The SAR requestor does not recognize the fact that the ERO has recognized the complexity associated with this area by initiating a Demand Resource Team.The question is “what is the reliability-need to analyze LSE load data when the PA’s data is the only relevant data for use in Planning Assessments”? Localized modeling may also use localized loads but that would be on a bus load basis not on an entity basis. Paragraph 1277Specific to the proposed changes to address the directive in Paragraph 1277, we question the basis for the 10% error if used as a threshold for R2. Further, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumptions even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2.
NERC Standards Review Subcommittee	No	#24. Please provide a basis for the 10% threshold since FERC did not state this in Order 693. Not sure how modifying load forecast assumptions to improve accuracy will benefit the BES unless the applicable entity applies it to the upcoming forecast. Short term forecasts can be off by more than 10% due to uncontrollable weather and long term forecasts can be off due to unforeseen economic conditions such as the 2008 / 2009 recessions. A zero DSM period could occur due to an unforeseen conditions making any forecast compared to zero more than a 10% error. Further DSM can be a very small portion of an overall forecast. Mandating a correction and applying a high VSL to future forecasts for events beyond an entity’s control (especially when the possibility of zero exists), i.e when a entity “failed to make improvements to improve accuracy”, is unrealistic.

Organization	Yes or No	Question 24 Comment
IESO	No	(1) Specific to the proposed changes to address the directive in Paragraph 1276, we generally agree with the changes to R1. (2) Specific to the proposed changes to address the directive in Paragraph 1277, we question the basis for the 10% error if used as a threshold for R2. Further, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumptions even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Further, the 10% threshold seems loose. Is it in effect saying that the responsible entity should review it forecasting process on an annual basis? Sometimes an error of 10% is totally explainable and should not warrant a change in forecast methodology (this is especially true for long term forecasts where weather is uncertain). It is prudent to review the methodology but to change it for changes sake is not. And does the load forecast mean Load forecast peak MW demand, peak hour energy demand, minimum demand, or all of the above?In addition, R2 is added without a corresponding M2. And why is Forecast (not a defined term) capitalized in R1.2 but not so elsewhere? Should interruptible demands be interruptible Loads?
Ameren	No	(a) R1.1 - Add ",DSM," after interruptible demands (b) R2 - what is the basis for 10%?
Northeast Power Coordinating Council	No	1. General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. With respect to Requirement R1.2 - How about simply ‘Summer and winter peak actual and weather corrected peak if observed, forecast load (one year ahead).’ This requires provision of the weather corrected actual which is directly comparable to the forecast. What is meant by “biasing of each load forecast”? 4. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 5. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 6. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.

Organization	Yes or No	Question 24 Comment
Santee Cooper	No	All Paragraphs - We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Arizona Public Service Company	No	AZPS agrees that the changes to R1 address Paragraph 1276 in Order 693. However, during the change process NERC has changed R1 to have sub-requirements R1.1 and R1.2. In doing so NERC has changed the meaning of R1. Prior to the change, R1 stated that annually as requested. Now the Standard states that the information shall be provided annually, yet R1.1 states as requested. This should be clarified to remove any confusion.Requirement R2 should be revised to state "... shall annually review the controllable load forecast ...". Order 693 direction is for controllable forecast, not Load forecast.
Consumers Energy Company	No	Changes for directives in Paragraph 1276: Disapprove Comments: As written, R1.2 and R2 apply to peak Load. They should apply Interruptible Demands and Direct Control Load Management, the subject of this standard. As is, they essentially duplicate the requirements of R1.5 and R2 of draft MOD-017. In R1.5 the term "peak Forecast variation" is not clear. Is this intended to be the difference between forecast and actual demand? Changes for directives in Paragraph 1277: Disapprove Comments: As written, R1.2 and R2 apply to peak Load. They should apply Interruptible Demands and Direct Control Load Management, the subject of this standard. As is, they essentially duplicate the requirements of R1.5 and R2 of draft MOD-017. In R1.5 the term "peak Forecast variation" is not clear. Is this intended to be the difference between forecast and actual demand? R2 (and therefore the VSL) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
Kansas City Power & Light	No	Directives 1276 and 1277:Do not agree with the concept of developing an indices that indicates the "accuracy, error and bias" between forecasted loads and actual loads as indicated by proposed additions of requirements R1.2 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to "normalize" actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different "latent heat" or "latent cold" build-ups. Poor indications of load accuracy are of no value and can be misleading.In addition, techniques developed by load forecasting groups to "compare" actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.It is inappropriate to include Regional Entities as an entity to provide forecasted load data. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain forecasted

Organization	Yes or No	Question 24 Comment
		load information as defined in this Standard MOD-019. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
E.ON U.S.	No	In paragraph 1276, FERC does not specify a five year minimum forecast period. The proposed revised standard does not identify the basis for the five year minimum. The time period for reporting may be covered in MOD16-1 R1 and may create conflicting requirements based upon time periods for data submittal. E ON U.S. suggests R1.1 be edited to read: "Forecasts of interruptible demands and Direct Control Load Management (DCLM) as contained in the documentation for MOD16-1for summer and winter peak system conditions." Regarding paragraph 1277, R2.2 should specify differences in controllable load. R2,2 also omits FERC directive to use five years of actual variations to improve the ten year forecast.
Florida Municipal Power Agency	No	In Paragraph 1276, this directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task. In Paragraph 1277, This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.
SDG&E	No	Issue:The language in MOD-019 is too broad in Requirement 2 - a new requirement for this standard. While the purpose of the standard is to focus on a forecast for Demand Response and DCLM, Requirement 2 states forecast without being specific. Second, the requirement also only allows for a 10% variance from forecast to actual, and we believe that in most years we will have a variance beyond the 10%, thus forcing us to develop a method to be closer to our forecast. Assuming that we have a weather anomaly, for which we have NO control, we would be unable to develop a method to stay within the 10% variance. We could also experience an Earthquake, or a fire, both of which will also be beyond our control. In the alternative, we should only have to develop an answer as to WHY our forecast was beyond the 10%

Organization	Yes or No	Question 24 Comment
		variance, and we should not have to develop a method to put us closer to our forecast. We may also want to suggest that NERC is confusing a planning forecast with an operating forecast, which are two separate environments.
Oklahoma Municipal Power Authority	No	It is not clear how the requirements in R2 are to be accomplished.
Georgia System Operations Corporation	No	Mod-019 R2. This requirement is a virtual copy of Mod-017 R2 and as written does not address FERC's directive. We believe the intended distinction between the two is that MOD-019 R2 should be focused on interruptible load. If so, it should be rewritten to reflect that. Our comment on MOD-017R2 regarding the need for a clear statement of conditions when action is required instead of giving an example of when action is required is also applicable here.
National Grid	No	o Requirement R1.2 should not be in this standard based on the title of the standard. The standard deals with interruptible demand and DCLM data and requirement R1.2 is more about load forecasting. National Grid suggests deleting R1.2. R1.2 can find place in MOD_17 standard. o With respect to Requirement R2.0 - Remove the wording in the parentheses. Also, delete it from the VSL. o General comment - In the "NERC Comments" section, remove the "Section B" descriptor of the Requirements. o General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. o General comment - Each entity's expertise should be relied upon to gather the appropriate weather information.
Southern Company Transmission	No	Paragraph 1276 - Adding sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. Paragraph 1277 - The proposed requirement R2, which includes review of Load forecast accuracy, goes beyond the FERC directive, which includes review of only controllable Load forecast accuracy. Even with that clarification, believe that industry will still consider this controversial. We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce reliability.

Organization	Yes or No	Question 24 Comment
SERC OC Standards Review Group	No	Paragraphs 1276 - 1277 - We suggest that R1.2 and R2 are not in scope for this standard. Also, last year NERC decided to stop using sub-requirements. (Jason will supply the details). While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Dominion	No	Paragraphs 1276 - 1277 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. 1. R1.5 - The language needs to be more specific as to which 'version' of the load forecast is to be compared to actual. Most entities forecast load for any given day at multiple intervals. As example DVP forecasts load for the future 7 days when weather forecast is updated (typically 0400, 1100, and 1600). Weather forecasts are also updated whenever the vendor determines a significant change from previous forecast occurs. This also triggers our load forecast software to produce an updated load forecast. During the actual day, the current day load forecast is updated each hour (for the remaining hours of the day) based upon preliminary 'actual load' for the preceding hour as well as any changes to the weather forecast for the current day.2. R2, as written, could decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.
ERCOT ISO	No	Q24 - The proposed language appears to address the directive, but ERCOT ISO disagrees with the added parenthetical language. Furthermore, ERCOT ISO disagrees with the phrase 'if necessary' because it introduces ambiguity.
Indiana Municipal Power Agency	No	Question 23 and 24 - This may be a bigger task than first thought by the SDT. In order to come up with R2 is to have an hour with DCLM and compare it against an hour without DCLM. Then one needs to do some extrapolation to the value of what would be available at peak load. IMPA believes there needs to be more involvement of the industry in this process and time to refine the method.In addition, there is no measure for requirement 2.
American Electric Power	No	R1.2. The standard title is "Forecasts of Interruptible Demands and DCLM Data" yet R1.2 reference peak forecast variation. Clarification is needed on what is peak (LSE, interruptible loads, etc). Secondly, "biasing of each forecast" is not appropriate phrasing. Loads are forecast to be as accurate as possible without bias. A series of actual loads compared to forecast may show a bias, but forecast are not developed with bias.
Springfield Utility Board	No	SUB respectfully disagress with the assessment that regulatory requirements are not burdensome. As a smaller utility looking to implement demand response via a pilot program of controlled demand, regulatory requirements are becoming overwhelming when considering the benefit of the program with the regulatory cost. Regulatory requirements are a barrier to entry for smaller entities. As a result, Demand Response may not be achieved as rapidly

Organization	Yes or No	Question 24 Comment
		as possible. There needs to be some ability implement small scale demand response programs without tripping all over requirements with excessive penalties. SUB is strongly considering not pursuing DR because of the risk associated with penalties from violations. A potential $4000 per month benefit is overwhelmed by the potential for a penalty that is ten times or a hundred times or a thousand times the value of the benefit. When looking at the serverity level associated with violations it is unjustifiable that a 200kW pilot project for demand response (as an example) that was not somehow captured correctly through a modified standard would trigger a high severity level. The severity level needs to better match the magnitude of the event.Direct Control Load Management in the NERC glossary is DSM that is controlled by the "system operator" (no caps). Yet the standard appears to require that forecasts reflect forecasts of "interruptible demands and Direct Control Load Management". The specific term DCLM which could be argued is important for grid reliability is being confused with "interruptible demands" which may not be controlled by the system operator and may not be known by the utility.The definition of DCLM uses the term "system operator" (no caps). The definition should be modifies to that it uses the term "System Operator"interruptible demands might include remote shut off of residential water heaters through a one way communication system which sends a signal for devices to shut off but the communication scheme may not know if the devices actually shut off or even if they were on to begin with. This is not something a system operator can rely upon for grid stability and it is impossible to evaluate variations in forecast. The standard is overly broad, the severity levels extreme, and SUB suggests modifying the severity level to better reflect the impact on the grid. "interruptible demands" should be capitalized. SUB suggests: 1) Eliminating interruptible demands from the requirement and just focus on DLCM. 2) Create a new standard for Interuptible Demands with lower severity levels and requirements to remove barriers for entry.
United Illuminating Company	No	United illuminating agrees with the intent but has concerns with the requirement R2. The statement in parenthesis is unclear if NERC is establishing 10% as the allowable variation or not. It's inappropriate to use e.g in a VSL matrix.UI suggests that the entity developing the Load Forecast maintains a document describing the allowable variation and how it is calculated
Midwest ISO Standards Collaborators	No	We do not believe that the directives in paragraph 1276 and 1277 represent low hanging fruit that can be accomplished by this ad hoc and expedited SAR. We believe the Commission likely would have the same view given their use of “innovative solutions” in their directive in paragraph 1276. Innovation takes time. Clearly, a group of experts needs to be convened in a drafting team to address this Commission directive. We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce

Organization	Yes or No	Question 24 Comment
		reliability. Adding sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Entergy Services	No	While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
PacifiCorp	Yes	R2 Requires accuracy of forecast vs. actual of within 10%--what level of granularity...BA, etc?Rephrase the language as follows:For Loads that vary based on temperature and/or humidity, temperature and humidity data for the prior year used to normalize demands.
Pepco Holdings, Inc. - Affiliates	Yes	the directive has been met by the changes, the world has advanced since Order 693, and this is not needed.

25. Do you believe the changes made in response to the directive(s) contained in Paragraph 1287 of Order No. 693 are both valid and address the directive(s)?

1287	We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	MOD-020-1	Modified Section B Requirement R1. Added Section B Requirement R2. Added VSLs for R2.

Organization	Yes or No
E.ON U.S.	No
National Grid	No
Xcel Energy	No
Northeast Power Coordinating Council	No
Kansas City Power & Light	No
Florida Municipal Power Agency	No
Oklahoma Municipal Power Authority	No
Dominion	No
Entergy Services	No
SERC OC Standards Review Group	No

Organization	Yes or No
Southern Company Transmission	No
Santee Cooper	No
ERCOT ISO	No
Indiana Municipal Power Agency	No
Pepco Holdings, Inc. - Affiliates	No
American Electric Power	No
Springfield Utility Board	No
Midwest ISO Standards Collaborators	No
IESO	No
Arizona Public Service Company	Yes
CECD	Yes
NERC Standards Review Subcommittee	Yes
PacifiCorp	Yes
SDG&E	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Illinois Municipal Electric Agency	Yes

Organization	Yes or No
Consumers Energy Company	Yes
Georgia System Operations Corporation	Yes

Comments on the MOD-020 Standard Changes

Summary Consideration:

The Response Team thanks all commenters for the thoughtful comments. The Response Team has considered the comments received and determined that modifications to address the P1287 directive will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration.

Organization	Question 25 Comment
Ameren	(a) R1 and R2.1 - Add ",DSM," after interruptible demands
IRC Standards Review Committee	Taken in isolation the proposed change to R1 is appropriate. All the identified entities must respond to data requests of reliability entities that require the data.In the context of the entire requirement, the proposed change does not address the definition and implication of DCLM. Such issues are in many cases state regulator related.FERC is correct that this is a complex issue and the idea that simply mandating forecast data ignores the fact of that complexity. The requirement lacks clarity in definition of what DCLM is; what biases the standard is seeking and who needs what information for reliability. The ERO has recognized the complexity associated with this area by initiating a Demand Resource Team. This change should take into account the findings of those initiatives.The proposed R2.1 computation/metric is a newly created requirement that is not required by the directive and should be processed through the Reliability Standards Development Process before it is approved.
Northeast Power Coordinating Council	1. General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. With respect to Requirement R2.1 - How is this different from MOD-019 R1.1? This seems like a duplication of what is in MOD-019 and perhaps, they should be combined.
Kansas City Power & Light	Directive 1287:Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted loads and actual loads as indicated by proposed additions of requirements R2 and R2.1. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading.In addition, techniques developed by

Organization	Question 25 Comment
	load forecasting groups to “compare” actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.It is inappropriate to include Regional Entities as an entity to provide forecasted load data. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain forecasted load information as defined in this Standard MOD-020. See definition below:Regional Entity - The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Florida Municipal Power Agency	In Paragraph 1287, this directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.
Oklahoma Municipal Power Authority	It is not clear on how the requirements in R2 are to be accomplished.
Dominion	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base loadIt should also be noted than if this requirement is approved, it may lead to the need for additional metering, which has been opposed by demand response as a ‘barrier to entry’. FERC has shown opposition to efforts at RTO/ISO forums that have proposed additional metering for demand response.
Entergy Services	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.
SERC OC Standards Review Group	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.

Organization	Question 25 Comment
Southern Company Transmission	Paragraph 1287 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.
Santee Cooper	Paragraph 1287 - We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
ERCOT ISO	Q25 - The language does seem to address the directive, but is likely to be controversial as it goes directly to telling how to do something rather than what needs to be done to ensure reliability. This standard needs to be fully vetted with the industry through the standards development process.
Indiana Municipal Power Agency	Question 25 - This may be a bigger task than first thought by the SDT. In order to come up with R2 is to have an hour with DCLM and interruptable demand, and compare it against an hour without DCLM and interruptable demand. Then one needs to do some extrapolation to the value of what would be available at peak load. IMPA believes there needs to be more involvement of the industry in this process and time to refine the method.In addition, there is no measure for requirement 2.IMPA does not see the need (or the directive order requirement) in requirement 2 to send this information to the ERO and Regional Entity. The information in requirement 2 should be sent to the requesting Transmission Operator, Balancing Authority, or Reliability Coordinator when they make the request in requirement 1. The ERO and Regional Entity can get the information formt eh Transmission Operator, Balancing Authority, or Reliablity Coordinator which is the way some regions are currently gathering this information.
Pepco Holdings, Inc. - Affiliates	R1 has been appropriately changed; R2 does not need to include the ERO
American Electric Power	R2.1 "...biasing of each forecast" is not appropriate phasing. Loads are forecast to be as accurate as possible without bias. A series of actual loads compared to forecast may show a bias, but forecast are not developed with bias.
Springfield Utility Board	SUB respectfully disagress with the assessment that regulatory requirements are not burdensome. As a smaller utility looking to implement demand response via a pilot program of controlled demand, regulatory requirements are becoming overwhelming when considering the benefit of the program with the regulatory cost. Regulatory requirements are a barrier to entry for smaller entities. As a result, Demand Response may not be achieved as rapidly as possible. There needs to be some ability implement small scale demand response programs without tripping all over requirements with excessive penalties. SUB is strongly considering not pursuing DR because of the risk associated with penalties from violations. A potential $4000 per month benefit is overwhelmed by the potential for a penalty that is ten times or a hundred times or a thousand times the value of the benefit.

Organization	Question 25 Comment
	When looking at the serverity level associated with violations it is unjustifiable that a 200kW pilot project for demand response (as an example) that was not somehow captured correctly through a modified standard would trigger a high severity level. The severity level needs to better match the magnitude of the event.Direct Control Load Management in the NERC glossary is DSM that is controlled by the "system operator" (no caps). Yet the standard appears to require that forecasts reflect forecasts of "interruptible demands and Direct Control Load Management". The specific term DCLM which could be argued is important for grid reliability is being confused with "interruptible demands" which may not be controlled by the system operator and may not be known by the utility.The definition of DCLM uses the term "system operator" (no caps). The definition should be modifies to that it uses the term "System Operator"interruptible demands might include remote shut off of residential water heaters through a one way communication system which sends a signal for devices to shut off but the communication scheme may not know if the devices actually shut off or even if they were on to begin with. This is not something a system operator can rely upon for grid stability and it is impossible to evaluate variations in forecast.The standard is overly broad, the severity levels extreme, and SUB suggests modifying the severity level to better reflect the impact on the grid. "interruptible demands" should be capitalized. SUB suggests:1) Eliminating interruptible demands from the requirement and just focus on DLCM.2) Create a new standard for Interuptible Demands with lower severity levels and requirements to remove barriers for entry.
Midwest ISO Standards Collaborators	We do not believe that the directives in paragraph 1287 represent low hanging fruit that can be accomplished by this ad hoc and expedited SAR. A group of experts needs to be convened in a drafting team to address this Commission directive. We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce reliability. Adding sub-requirement R2.1 and modifying sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
IESO	We do not understand the meaning of "biasing". Is it operator adjustments? If so, isn't forecaster/operator expertise part of the forecasting process? Forecasting (especially long term) is not just a mechanical exercise but requires "value-added" actions by the forecaster. Biasing is not a defined term.
Illinois Municipal Electric Agency	Many Reliability Standards Requirements could be eliminated by simply requiring a registered entity to comply with requests from its interconnected functional authorities as part of its registration obligations.

Organization	Question 25 Comment
Consumers Energy Company	Please provide your opinion regarding the Paragraph 1287 VRF and VSLs: In Favor
Georgia System Operations Corporation	Recommend re-writing R2 to not have sub-requirements since there is only one (1) sub-requirement.

26. Do you believe the changes made in response to the directive(s) contained in Paragraph 1300 of Order No. 693 are both valid and address the directive(s)?

1300	The Commission directs the ERO to modify the title and purpose statement to remove the word "controllable." We note that no commenter disagrees.	MOD-021-1	Modified Section A 1 and 3.

Organization	Yes or No
Northeast Power Coordinating Council	No
Ameren	Yes
American Electric Power	Yes
Arizona Public Service Company	Yes
CECD	Yes
Consumers Energy Company	Yes
Dominion	Yes
E.ON U.S.	Yes
Entergy Services	Yes
ERCOT ISO	Yes
Florida Municipal Power Agency	Yes
IESO	Yes
Illinois Municipal Electric Agency	Yes
Indiana Municipal Power Agency	Yes

Organization	Yes or No
IRC Standards Review Committee	Yes
Kansas City Power & Light	Yes
National Grid	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Santee Cooper	Yes
SDG&E	Yes
SERC OC Standards Review Group	Yes
Southern Company Transmission	Yes
Springfield Utility Board	Yes
United Illuminating Company	Yes
Western Electricity Coordinating Council	Yes
Xcel Energy	Yes
Georgia System Operations Corporation	Yes
Midwest ISO Standards Collaborators	Yes

Comments on the MOD-021 Standard Changes

Summary Consideration:

The majority of commenters agree with the proposed modifications to address this directive. The Response Team thanks the commenters for their support.

Organization	Question 26 Comment
Northeast Power Coordinating Council	1. General comment - If the Transmission Planner gets its information from the LSE, must it duplicate the documentation? The impact of many DSM programs is not measurable. Response: The Response Team does not understand the comment/question. We suggest the commenter to seek informal guidance or request for an interpretation if this relates to the clarity of the existing standard.
Georgia System Operations Corporation	None.
Midwest ISO Standards Collaborators	We agree this represents low hanging fruit that could be modified through this expedited SAR. We do note though that the Compliance section of the standard has been modified which exceeds the scope of the SAR. Response: Thank you for the support. The compliance elements, which are not considered part of the standard, have been updated to reflect the current practices in use today. They do not conflict with the requirements, do not impose any new requirements, and should provide more clarity to entities wishing to comply with the standard. As such, the Response Team believes the updates are both appropriate and within scope.

27. Do you believe the changes made in response to the directive(s) contained in Paragraph 1469 of Order No. 693 are both valid and address the directive(s)?

1469	Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.	PRC-004-2	Modified Section B Requirements R1, R2, and R3.
1469	We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.	PRC-004-2	Modified Section B Requirements R1 and R3. Modified Measures M1 and M3. Modified Data Retention.

Organization	Yes or No
NERC Standards Review Subcommittee	No
Ameren	No
Northeast Power Coordinating Council	No
Consumers Energy Company	No
Kansas City Power & Light	No
Georgia System Operations Corporation	No
American Electric Power	No
Central Lincoln	No
Entergy Services	No
SERC OC Standards Review Group	No
Midwest ISO Standards Collaborators	No

Pepco Holdings, Inc. - Affiliates	No
PacifiCorp	No
ERCOT ISO	No
E.ON U.S.	No
United Illuminating Company	No
IESO	No
Southern Company Transmission	No
Arizona Public Service Company	Yes
CECD	Yes
Dominion	Yes
Dynegy Inc.	Yes
National Grid	Yes
Oklahoma Muncipal Power Authority	Yes
Santee Cooper	Yes
Springfield Utility Board	Yes
US Bureau of Reclamation	Yes
Xcel Energy	Yes
Illinois Municipal Electric Agency	Yes

Indiana Municipal Power Agency	Yes
Florida Municipal Power Agency	Yes
Western Electricity Coordinating Council	Yes

Comments on the PRC-004 Standard Changes

Summary Consideration:

Many commenters disagree with the inclusion of Load-Serving Entity and Transmission Operator in the Applicability Section and in Requirements R1 and R3 since these entities are not owners of BES facilities. Upon reviewing these comments and the Functional Model, the Response Team agrees with the commenters' view. The proposed modifications to address the ISO-NE's suggestion, namely, to include LSE and TOP in the PRC-004 standard, have been removed from consideration for balloting. With this decision, comments addressing these particular changes will be not be responded to individually at this time. However, they will be retained for future consideration.

Some commenters indicate that the change from RRO to RE in the Requirements needs to be reflected in the Measures. The Response Team agrees and has changed Measures M1, M2 and M3 by replacing "Regional Reliability Organization procedures developed for PRC-003 R1" with "Regional Entity's procedures."

Some commenters disagree with replacing Regional Reliability Organization with Regional Entity as directed by the Commission in Order 693, Paragraph 1469. Version 5 Reliability Functional Model Technical Document, Ch. 15 indicates that: "NERC is the Compliance Enforcement Authority. The Regional Entities have a major role in the actual performance of the monitoring, under delegated authority from NERC." We do not find using the term Reliability Entity inappropriate. The proposed change to Requirement R2 and the Compliance Section are retained and will be included in the recirculation ballot.

Organization	Question 27 Comment
IRC Standards Review Committee	Taken in isolation the proposed changes to R1, R2 and R3 are appropriate.In the context of the entire requirement, the proposed change raises the following issues: o The LSE should not be included in requirements R1 and R3 because they are not required to have any assets that would be used for mitigation of generator protection systems misoperations. LSEs arrange energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end-use customers. They do not own, or need to own, any transmission, generation or distribution facilities and their associated protection systems. Further, since both LSEs and TOPs do not own physical assets, they should not be included in the applicability section. ISO-NE, who originally submitted the comment which resulted in the Directive, agrees and believes that the directive is no longer applicable. o The changes to R1 are problematic because they introduce a joint applicability (i.e. joint ownership of a Protection System). FERC has required clear applicability - and joint applicability raises the question of how to split responsibility and compliance regarding the mandate to analyze a misoperation, and to develop a mitigation plan. Response: Please see the response in Summary of Consideration.
NERC Standards Review	#27. FERC Order 693 does not state that "individually or jointly" entities that own a Protection System shall analyze and develop a

Organization	Question 27 Comment
Subcommittee	Correction Action Plan. This statement does not improve this Standard. Anyone of the applicable entities can be joint owners of a transmission Protection System but one entity will have this requirement to fulfill those actions of this requirement. Recommend deleting “individually or jointly”. Response: The proposed change goes beyond the scope of this project. However, with the decision to not proceed with changes to R1 and R3 to address the directive, your suggestion will be retained for future consideration when the standard is revised.
Ameren	(a) The Glossary of Terms still uses RRO, why the change to Regional Entity? (b) The industry has finally approved Project 2009-17 which clarifies the transmission Protection System border. But 2009-17 refers to PRC-004-1. Please expand 2009-17 so that it is applicable to this proposed PRC-004-2, or better yet incorporate the 2009-17 wording into PRC-004-2. (c) We do not believe that LSE and TOP would own Protection Systems. The standard should not apply to LSE and TOP. Response: Please see the response in Summary of Consideration.
Northeast Power Coordinating Council	1. Since LSEs and TOPs do not own physical assets, they should not be included. ISO - NE agrees and believes that the directive is no longer applicable. 2. There is still no clarification on when a DP "owns" a transmission Protection System. Distribution Providers likely own and/or operate equipment matching the definition in the NERC Glossary; however, such does not constitute the owning and/or operation of a “transmission” protection system. In what instances would the NERC Glossary definition of a Protection System apply to a DP?3. R3 should be reworded to reflect RE just like the other requirements have been modified. Response: Please see the response in Summary of Consideration.
Consumers Energy Company	Comments: Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot “own” facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE’s suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM. Response: Please see the response in Summary of Consideration.

Organization	Question 27 Comment
Kansas City Power & Light	Directive 1469:It is inappropriate to include Regional Entities as an entity that establishes the criteria and procedures for analysis and reporting of relay mis-operations. The requirements should continue to point to the Regional Reliability Organization or the Reliability Coordinator as the entity that establishes the criteria and procedures for analysis and reporting of relay mis-operations. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to establish the criteria and procedures for analysis and reporting of relay mis-operations as defined in this Standard PRC-004. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.In addition, it is sufficient to include as an applicable entity the Transmission Owner. It is not necessary, nor is the directive concerned with, the inclusion of the Transmission Operator. The NERC Functional Model clearly indicates the relaying system is the responsibility of the Transmission Owner and not the Transmission Operator. Recommend removal of the Transmission Operator from the Applicability Section and the subsequent references in the requirements. Response: Please see the response in Summary of Consideration.
Georgia System Operations Corporation	Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and therefore should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and therefore should be removed.R3 refers to Regional Reliability Organization and Regional Entity in the same sentence. The same inconsistency exists in the Measures. Response: Please see the response in Summary of Consideration.
American Electric Power	If these changes are made, this will create applicability to entities that are not involved in other related PRC standards. AEP does not support this "urgent" action as it will create confusion between this and other PRC standards going forward. Furthermore, in AEP's experiences, TOP and LSEs are likely not to have involvement in these requirements, but it should be the TO, DP and GO that are involved.The inclusion of the LSE in this standard continues to muddy the water between the role of the LSE and the DP. The NERC Statement of Registry Criteria states that a DP "Provides and operates the 'wires' between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage." In addition, an LSE is defined as an entity that "secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers."This issue has been a considerable problem with how standards were written in the past and NERC has committed to addressing these unfortunate and confusing overlaps in responsibility, but these proposed changes will only perpetuate the problem. We recommend that any entity

Organization	Question 27 Comment
	that has such protection systems should be registered as a TO, DP or GO, The issue then would become one of the ability of the RE to appropriately register entities, not a deficiency in the NERC standards.Again, the other PRC standards are focused on the TO function. This would again cause a mismatch in the applicability with these standards. The first sentence of requirement R1 should be revised to begin "The Transmission Owner, Distribution Provider and the Generator Owner that individually or jointly owns a transmission Protection System, shall each..." AEP Generation owns transmission Protection Systems and believes that the intent of this standard is that all transmission Protection System misoperations are analyzed, regardless of the ownership of the equipment. Furthermore, revising requirement R1 brings the analysis requirements in line with the documentation requirements of R3 which requires a Generator Owner who owns a transmission Protection System to "... provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans...". Also, note that “Regional Reliability Organization” should actually be “Regional Entity”. Measure M1 should be revised to include the Generator Owner, as suggested above, and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures." Measure M2 should be revised to be consistent with R2 and read "The Generator Owner shall have evidence it analyzed its generator Protection System Misoperations..." and to and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures." Measure M3 should be revised to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures." The Data Retention section should be revised to remove reference to the "generation Protection System" and should instead read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall retain..."The Additional Compliance Information section should be revised to read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall demonstrate..." Response: Please see the response in Summary of Consideration.
Central Lincoln	It remains unclear how an entity can comply with any of the requirements in the absence of a Regional Entity procedure. Response: Please see the response in Summary of Consideration.
Entergy Services	Paragraph 1469 - Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.2 and R1.3 should be included in this standard.

Organization	Question 27 Comment
	Likewise, we do not believe that R3.2 and R3.3 should be included in this standard. Response: Please see the response in Summary of Consideration.
SERC OC Standards Review Group	Paragraph 1469 - Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and, therefore; should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and, therefore; should be removed. Response: Please see the response in Summary of Consideration.
Midwest ISO Standards Collaborators	Paragraph 1469 clearly states the Commission's expectation that this directive will be addressed through the five-year cycle. Why does this need to be expedited? However, we agree that the changes meet the directive regarding modifying regional reliability organization to Regional Entity. The Commission's directive is to consider adding LSE and TOPs to PRC-004-1 not to actually add them. LSEs and TOPs have no Protection Systems to coordinate. They are not equipment owners per the Functional Model. We agree that the Distribution Provider is a likely candidate for coordination. While the functional model does mention the need for Transmission Owners to develop interconnection agreements with Distribution Providers, it currently is silent on the need to coordinate Protection Systems and appears to give the responsibility for Protection Systems entirely to the Transmission Owner. We suggest that this directive should be referred to the Functional Model Working Group for a proposed resolution and modification of the functional model as necessary. Then a SAR could be developed to address to the Functional Model. Adding sub-requirements R1.1 through R1.3 and R3.1 through R3.3 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. Response: Please see the response in Summary of Consideration.
Pepco Holdings, Inc. - Affiliates	Pepco Holdings Affiliates believe the SDT has erred in stating that a protection system may be jointly owned. This was not an issue in Order 693. By definition, A TOP would not own a protection system. Order 693 did not require the addition of LSEs or TOPs, only that they be considered. An LSE that "owns" a protection system is also a DP, so LSE applicability is not needed. Response: Please see the response in Summary of Consideration.

Organization	Question 27 Comment
PacifiCorp	PRC-004-2 should be applicable to either the Transmission Owner/Generator Owner or the Transmission Operator/Generator Operator, but not both. If PRC-004-2 is applicable to both Transmission Owner/Generator Owner and Transmission Operator/Generator Operator, the standard should more clearly define how the standard applies to each of these entities. In many instances, a Protection System may be owned by one entity but operated by another. Furthermore, in many instances, both the owner and operator of the Protection System are registered as Transmission Owner and Transmission Operator. Given this factual scenario and the currently proposed PRC-004-2, both entities could individually be responsible for compliance related to the same Protection System. As currently written, it is unclear whether this is the intent of the standard. In order to provide responsible entities with clear guidance on their regulatory responsibilities, PacifiCorp suggests that the standard clearly identify only one entity that is responsible for compliance. Short of this, PacifiCorp suggests that the standard more clearly state how it applies to each of the responsible entities listed. Response: Please see the response in Summary of Consideration.
ERCOT ISO	Q27 - The changes made appear to assume that Regional Entities, Load Serving Entities, and Transmission Operators are operating entities when in fact REs and LSEs are not operating entities. There is not a direct one to one correlation between RRO and RE. The SDTs have been directed by NERC, as they work on the standards revision projects, to assign RRO responsibilities to the appropriate functional entities. ERCOT ISO agrees that TOPs should be added to the applicability section. Response: Please see the response in Summary of Consideration.
E.ON U.S.	The FERC's directive is to change references from RRO to RE. R3, M1,M2 and M3 still reference RRO. Response: Thank you for catching the discrepancy. Measures M1, M2 and M3 have been revised accordingly to replace "Regional Reliability Organization procedures developed for PRC-003 R1" with "Regional Entity's procedures."
United Illuminating Company	United Illuminating believes the transmission owner should be listed in the sub bullet 1.1. R1 should start "Any entity listed below that individually or jointly...". Same comment for R3. United Illuminating points out to the Drafting Team that Paragraph 1469 also refers this change to PRC-005, 8, 11, 15, 16, 17, 21. Response: Please see the response in Summary of Consideration. Your specific suggestions will be considered in future revision to this standard.
IESO	We agree with the proposed changes to the Applicability Section, Requirements R1, R2 and R3 except the inclusion of the Load-Serving Entity. LSEs arrange secures energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end-use customers. They do not own, or need to own, any transmission, generation or

Organization	Question 27 Comment
	distribution facilities and their associated protection systems.We suggest to remove LSE from the Applicability Section and the three requirements. Further, there are two typos in R3: the “o” in “Generation owner” should be capitalized; and “Regional Reliability Organization” should be “Regional Entity”. Response: Please see the response in Summary of Consideration
Southern Company Transmission	With respect to the FERC Order 693 directive in Paragraph 1469, the reference to the Regional Reliability Organization in R3 should be replaced with the Regional Entity.(replace “... shall each provide to its Regional Reliability Organization...” with “...shall each provide to its Regional Entity...”) M1, M2, and M3 need to be changed to match R1, R2, and R3 by:(replacing “... according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.” with “... according to the Regional Entity’s procedures.”) Requirement 1 refers to transmission protection systems in the case of TO's, DP's, TOP"S and LSE's while Requirement 2 specifically mentions generator protection systems in reference to GO's. In Requirement 3 however it is unclear whether Generator Owners are held responsible for generator protection systems, transmission protection systems or both. Compliance Section - Data Retention - Is the intent that GO's should retain data for an evaluation not prescribed in the Requirements - in the case of a Generator Owner evaluating transmission protection systems? Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and therefore should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and therefore should be removed.The Commission’s directive is to consider adding LSE and TOPs to PRC-004-1 not to actually add them. LSEs and TOPs have no Protection Systems to coordinate. They are not equipment owners per the Functional Model. We agree that the Distribution Provider is a likely candidate for coordination. While the functional model does mention the need for Transmission Owners to develop interconnection agreements with Distribution Providers, it currently is silent on the need to coordinate Protection Systems and appears to give the responsibility for Protection Systems entirely to the Transmission Owner. We suggest that this directive should be referred to the Functional Model Working Group for a proposed resolution and modification of the functional model as necessary. Then a SAR could be developed to address to the Functional Model. Response: Please see our response in Summary Consideration. In addition, thank you for catching the discrepancy. Measures M1, M2 and M3 have been revised accordingly to replace “Regional Reliability Organization procedures developed for PRC-003 R1” with “Regional Entity’s procedures.”

Organization	Question 27 Comment
Illinois Municipal Electric Agency	Can live with, but addition of LSE does not make sense given current Reliability Functional Model definition. Also, revisions are not consistent with our understanding of NERC's intent to get away from the sub-requirement structure. Response: Please see our response in Summary Consideration.
Indiana Municipal Power Agency	IMPA supports this change, but transmission protection system needs to be defined by a SDT in the near future. Response: The definition of protection system is being addressed under a separate project.
Florida Municipal Power Agency	The directive is to "consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section". In this case, while we do not oppose the change, we do not know of any cases where an LSE or TOP has a transmission Protection System, so, we do not know why LSEs and TOPs are being added to the applicability. Can someone identify a transmission Protection System owned by an LSE or TOP that is not already covered by a TO, GO or DP? Response: Please see our response in Summary Consideration.
Western Electricity Coordinating Council	While the proposed changes are to PRC-004, PRC-003-0 is a Fill-in-the-blank standard and is referenced by PRC-004. As NERC revises the Fill-in-the-blank standards to remove the Regional Reliability Organization as an applicable entity, the language of PRC-004-2 (as well as many others) will need to be revised to remove the phase "according to the Regional Entity's procedures." Response: The Response Team agrees with your view. However, until PRC-003 is revised, PRC-004 still needs to make reference to an approved standard. Your comments will be considered in future revisions to the inter-related standards.

28. Do you believe the changes made in response to the directive(s) contained in Paragraph 1858 of Order No. 693 are both valid and address the directive(s)?

1858	The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	VAR-001-2	Added Section A 4.3. Modified Section B Requirement R5.

Organization	Yes or No
Ameren	No
American Electric Power	No
CECD	No
Consumers Energy Company	No
Entergy Services	No
ERCOT ISO	No
IESO	No
Kansas City Power & Light	No
National Grid	No
Northeast Power Coordinating Council	No
Santee Cooper	No
SERC OC Standards Review Group	No
Springfield Utility Board	No
Arizona Public Service Company	Yes

Organization	Yes or No
Dominion	Yes
Dynegy Inc.	Yes
E.ON U.S.	Yes
Florida Municipal Power Agency	Yes
Georgia System Operations Corporation	Yes
Illinois Municipal Electric Agency	Yes
Indiana Municipal Power Agency	Yes
Midwest ISO Standards Collaborators	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
Southern Company Transmission	Yes
US Bureau of Reclamation	Yes
Western Electricity Coordinating Council	Yes
Xcel Energy	Yes

29. Do you believe the changes made in response to the directive(s) contained in Paragraph 1879 of Order No. 693 are both valid and address the directive(s)?

1879	The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1.	VAR-001-2	Modified Section B Requirements R2, R5, R8, and R9.

Organization	Yes or No
National Grid	No
Xcel Energy	No
Springfield Utility Board	No
Ameren	No
United Illuminating Company	No
Georgia System Operations Corporation	No
CECD	No
Consumers Energy Company	No
IESO	No
E.ON U.S.	No
Northeast Power Coordinating Council	No
Southern Company Transmission	No
Santee Cooper	No

Organization	Yes or No
Entergy Services	No
SERC OC Standards Review Group	No
ERCOT ISO	No
Midwest ISO Standards Collaborators	No
Arizona Public Service Company	Yes
Dynegy Inc.	Yes
Florida Municipal Power Agency	Yes
Illinois Municipal Electric Agency	Yes
Indiana Municipal Power Agency	Yes
NERC Standards Review Subcommittee	Yes
Oklahoma Muncipal Power Authority	Yes
PacifiCorp	Yes
Pepco Holdings, Inc. - Affiliates	Yes
US Bureau of Reclamation	Yes
Western Electricity Coordinating Council	Yes
American Electric Power	Yes
Kansas City Power & Light	Yes

Organization	Yes or No
Dominion	Yes

Comments on the VARV-001 Standard Changes

Summary Consideration:

Many commenters disagree with including “load shedding” in the proposed changes to Requirements R2, R5 and R9. The Response Team agrees with their comments, and has removed this term from Requirements R2, R5 and R9.

Some commenters suggest removing R5 altogether. The proposed change to R5 is meant to address deficiencies of the approved VAR-001 standard as directed by the Commission and the ERO must address these directives. The proposal to strike R5 or to change the language to reflect the tariff requirements for arranging reactive support will be considered in future revision to this standard.

Some commenters disagree with the insertion of the list of reactive resources. The insertion is meant to provide examples of control measures that are resource and business arrangement neutral and can be arranged or deployed to provide the needed reactive capability.

Some commenters suggest replacing the TSP with the TOP in R5. This suggestion will be retained for consideration in future revisions as this change is outside of the scope of this Project.

Some commenters disagree with the use of the term “controllable load”. The intent is to keep it broad to enable this round of changes to meet the directives. Defining this term or use of an alternate term such as Direct Control Load Management (DCLM) raises other arguments which will require much more discussion to arrive at industry consensus. Nonetheless, this suggestion will be retained for consideration in future revisions.

Organization	Question 29 Comment
IRC Standards Review Committee	Paragraph 1819The mark-up to R9, as written, implies that load shedding can be used for first Contingency conditions since first contingency includes single contingencies. We disagree with this change, and suggest that load shedding be removed from the requirement. In fact, the list of actions need not be included in the requirement since the inclusion of a list of reactive services is not appropriate without proper vetting. Paragraph 1858Taken in isolation the proposed changes to R5 are appropriate.The issue is with the requirement itself. R5 inappropriately identifies the TSP as the entity responsible for identifying reactive requirements. It should be the TOP that is responsible for identify this requirement. Response: The Response Team agrees with the concern over “load shedding”, and has removed this term from Requirements R2, R5 and R9. With respect to the comment on including the list of actions, these are included as possible actions since the requirement clearly indicates “may include, but not limited to”. This provides the flexibility without mandating that the Responsible Entity apply all of the listed actions or restricting the Responsible Entity from applying other actions. With respect to the TOP versus TSP comment, we will retain this comment for consideration in future revisions, as this change is

Organization	Question 29 Comment
	outside of the scope of this Project.
central Maine Power Company	R10 which is not addressed by this but should be. A violation does not occur until after the 30 minutes has expired. Until then the requirement is being exceeded. TOP-007 has similar wording which is confusing and incorrect. Response: We will retain this comment for consideration in future revisions, as this change is outside of the scope of this Project.
Springfield Utility Board	"controllable load" is not a defined term and is too broad. "load shedding" is not a defined term and is too broad. The NERC glossary of terms uses "Direct Control Load Management" (which needs to be modified so that "system operator" is in caps "System Operator"). SUB appreciates the intent, but the proposed changes make the situation worse, do not improve reliability, increase confusion and lack of clarity, pull in DSM programs which have no bearing on voltage or reactive control, and diminish reliabilty.The language referring to controllable load and laod shedding should be eliminated and replaced with "Direct Control Load Management".language change:"which may include, but is not limited to, reactive generationscheduling; transmission line and reactive resource switching, and, if necessary, Direct Control Load Management" Response: The Response Team has removed the term “load shedding” from Requirements R2, R5 and R9. With respect to the use of the term “controllable load”, the intent is to keep it broad to enable this round of changes to meet the directives. Defining this term or use of DCLM raises other arguments which will require much more discussion to arrive at industry consensus. Nonetheless, we will retain this comment for consideration in future revisions.
Ameren	(a) R2 - load shed is not a resource but a stop gap (b) R5 - Add "for all load levels it expects to have on the TSP system" removing "controlled load, and if necessary, load shedding". (c) R5 - How does PSE arrange for load shedding? Response: The Response Team has removed the term “load shedding” from Requirements R2, R5 and R9. With respect to the use of the term “controllable load”, the intent is to keep it broad to enable this round of changes to meet the directives. Defining this term or use of DCLM raises other arguments which will require much more discussion to arrive at industry consensus. Nonetheless, we will retain this comment for consideration in future revisions.
United Illuminating Company	United Illuminating disagrees with including load shed in R2. R2 is in a planning horizon versus R8 and R9 which is in real-time operating horizon. United Illuminating does not believe it is appropriate PLAN on load shed to meet a reactive requirement. Load shed (R8 and R9) is appropriate in the real time environment to protect the BES. Response: The Response Team has removed the term “load shedding” from Requirements R2, R5 and R9.
Georgia System Operations	29) We disagree with the inclusion of load shedding as a resource in VAR-001 R2, R5, and R9. Controllable load is certainly a

Organization	Question 29 Comment
Corporation	resource and that is what FERC directed to be included. Load shedding is certainly an appropriate action to be included in requirement R8, but considering load shedding (as distinct from controllable load) as a resource would only allow an entity to carry less true resources to meet the requirement. Perversely the inclusion of load shedding as a resource would make it difficult to violate the requirement, because an entity would always have sufficient load shedding resources (you can shed your entire load in theory). Response: The Response Team has removed the term “load shedding” from Requirements R2, R5 and R9.
CECD	CECD is concerned with the impact to the BA if load shedding is used as a reactive resource and feels that the standard must be modified to require the TOP notify the BA if load shedding is applied in this manner. Response: The Response Team has removed the term “load shedding” from Requirements R2, R5 and R9.
Consumers Energy Company	Changes for directives in Paragraph 1858: Disapprove Comments: Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot “own” facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE’s suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM. Changes for directives in Paragraph 1879: Disapprove Comments: Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot “own” facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE’s suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM. Response: LSE is included in R5 only, which we assess is appropriate since it is defined as: “The functional entity that secures energy and transmission service (and reliability related services) in the current Functional Model. Regarding your comment on TOP versus TO, R1 and R3 stipulates the requirement in an operating environment. We do not see any wording in these Requirements that suggest “owning” facilities as you indicate. We agree with you that LSEs and TOPs are operating entities, and that is exactly what this standard is meant to address (the operating domain). We do not see any issues with including LSEs and TOPs (and PSEs) in this standard.
IESO	For Para 1858, we agree with the additional wording in Requirement R5 but there is a fundamental issue with the last part of the requirement as written. The TSP should not be the entity responsible for identifying reactive requirements. It should be the TOP

Organization	Question 29 Comment
	that is responsible for identify this requirement. Response: With respect to the TOP versus TSP comment, we will retain this comment for consideration in future revisions as the proposed change is outside of the scope of this Project.
E.ON U.S.	In paragraph 1879, FERC says to “consider the concern...”, not to actually change requirements. Providing optional methods or examples does not add clarity to the standard Response: The Commission did not ask the ERO to consider. Paragraph 1879 clearly states that the Commission “…direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1”. The proposed changes comply with this directive.
Northeast Power Coordinating Council	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. The mark-up to R9, as written, implies that load shedding can be used for first contingency conditions. This is detrimental to reliability. Response: With respect to the comment on specific technologies, the proposed changes make no mention of any technologies. We suspect this comment is intended for another standard. With respect to “load shedding”, the Response Team has removed this term from Requirements R2, R5 and R9.
Southern Company Transmission	Paragraph 1858 - However, this is a tariff issue and unrelated to reliability. Paragraph 1879 - In R9, shedding load following the first contingency would seem to violate TPL-002, Category B events. Response: The Response Team has removed this term from Requirement R9.
Santee Cooper	Paragraph 1858 - Requirement 5 should be removed completely as we consider this to be tariff related and not reliability related. Paragraph 1879 - Recommend removing the insertions in Requirement 2 and Requirement 9. We recommend removing Requirement 5 completely for reason stated above. Requirement 8 we recommend removing all the wording between the dashes. Response: Regarding R5, Removing this requirement is outside of the scope of this project. Nonetheless, this comment will be considered in future revisions. With respect to removing the insertion in R2, R8 and R9, the list of actions are included as possible measures to clarify the “which may include, but not limited to”. This provides flexibility without mandating that the Responsible Entity apply all of the listed actions or restricting the Responsible Entity from applying other actions.

Organization	Question 29 Comment
Entergy Services	Paragraph 1858 - We suggest striking all of R5. The requirement for the Transmission Customer to purchase ancillary services including voltage support, and the ability to self-supply is a tariff issue and unrelated to reliability.1879 - R2 and R9 - We suggest striking the insertions. In R8 we suggest striking "- which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding -". This makes the standard resource neutral, which is apparently the aim of FERC. Including a partial list of resources that qualify as reactive resources, does not improve the reliability of the standard. Response: Regarding R5, Removing this requirement is outside of the scope of this project. Nonetheless, this comment will be considered in future revisions. With respect to removing the insertion in R2, R8 and R9, the list of actions are included as possible measures to clarify the "which may include, but not limited to". This provides flexibility without mandating that the Responsible Entity apply all of the listed actions or restricting the Responsible Entity from applying other actions. We feel that this flexibility supports the "resource neutral" notion.
SERC OC Standards Review Group	Paragraph 1858 - We suggest striking all of R5. This is a tariff issue and unrelated to reliability.1879 - R2 and R9 - We suggest striking the insertions. In R8 we suggest striking "- which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding -". This makes the standard resource neutral, which is apparently the aim of FERC. Response: Regarding R5, Removing this requirement is outside of the scope of this project. Nonetheless, this comment will be considered in future revisions. With respect to removing the insertion in R2, R8 and R9, the list of actions are included as possible measures to clarify the "which may include, but not limited to". This provides flexibility without mandating that the Responsible Entity apply all of the listed actions or restricting the Responsible Entity from applying other actions. We feel that this flexibility supports the "resource neutral" notion.
ERCOT ISO	This standard needs to be fully vetted with the industry through the standards development process. Reactive resources and reactive services will be controversial due to the varying market structures in which these products are arranged and provided. Response: The proposed changes to R2, R5 and R9 serve to provide examples which are resource and business arrangement neutral.
Midwest ISO Standards Collaborators	We agree that the changes address paragraph 1858 but question the need for the changes or even the need for the existing requirement. This requirement is essentially a reflection of the FERC pro-forma tariff requirement that transmission customers (usually PSEs) must purchase reactive service or arrange for it themselves. Has any PSE ever arranged reactive service themselves? The transmission operator will still have to take the necessary steps to ensure reactive power is sufficient to support voltage. While changes to R2, R5, R8 and R9 may address the Commission directives in paragraph 1879, we do not agree with the

Organization	Question 29 Comment
	changes and believe a better solution is available. Rather than adding a laundry list of methods to control voltage, we suggest the requirements should be silent on the methods. Thus, we suggest that the additions to R2, R5, R8 and R9 be removed and that "reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding" be struck from R8. In this way, Commission's goal of ensuring the reliability standards do not prevent Commission policy from being implemented is met. The proposed changes appear to be using Reliability Standards to further Commission policy on demand response which is surely not their intent since Reliability Standards are about maintaining a reliable grid.We agree that no changes are necessary to the standard to address SoCal Edison's concerns in paragraph 1878. NERC simply needs to offer their explanation in the regulatory filing. Response: The proposed changes are meant to address deficiencies of the approved VAR-001 standard as directed by the Commission which the ERO must comply. The issue with whether or not PSE or LSE needs to comply with a reliability standard that may be viewed as a tariff requirement will be debated in future major revision to this standard. The proposed changes to R2, R5 and R9 serve to provide examples of control measures which are resource and business arrangement neutral that can be deployed to provide the needed reactive capability. The Response Team has removed the term "load shedding" from Requirements R2, R5 and R9.
American Electric Power	AEP does not agree with expanding the scope to the LSE in R5. Furthermore, the existing applicability to the PSE is not a reliability related requirement as this service is provided by the TSP by default. We do not agree with adding "which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load, and, if necessary, load shedding -" to R5 for the PSE and LSE functions. These entities do not have many of the capabilities as listed. Response: The proposed change to R5 is meant to address deficiencies of the approved VAR-001 standard as directed by the Commission which the ERO must comply. The issue with whether or not PSE or LSE needs to comply with a reliability standard will be debated in future major revision to this standard. The proposed changes to R2, R5 and R9 serve to provide examples of control measures which are resource and business arrangement neutral that can be arranged or deployed to provide the needed reactive capability. We agree that the PSE and LSE may not have many of the capabilities as listed. However, Requirement R5 asks that they "…arrange for (self-provide or purchase) reactive resources…". We do not think that their limited capability is an impediment to complying with the requirement.
Kansas City Power & Light	Directive 1858:The Purchase-Selling will have provisions for reactive support within the ancillary services available to it. Recommend modifying the language in requirement R5 to reflect the exercise of reactive support as provided within the ancillary services available and remove the prescriptive parts of this requirement related to the various actions that can be taken by a

Organization	Question 29 Comment
	Transmission Operator or Transmission Service Provider. Response: The proposed change to R5 is meant to address deficiencies of the approved VAR-001 standard as directed by the Commission and the ERO must address the directives. The proposal to modifying the language in requirement R5 to reflect the exercise of reactive support as provided within the ancillary services available will be considered in future revision to this standard. The listing provides examples of control measures which are resource and business arrangement neutral that can be arranged or deployed to provide the needed reactive capability.
Dominion	Paragraph 1858 - We suggest striking all of R5. These requirements are contained in each Transmission Service Provider's tariff. This issue can impact reliability only when the entity substantially fails to meet its obligation under the respective OATT. 1879 - R2 and R9 - We suggest striking the insertions. In R8 we suggest striking "- which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding -". This makes the standard resource neutral, which is apparently the aim of FERC. Response: The proposed change to R5 is meant to address deficiencies of the approved VAR-001 standard as directed by the Commission which the ERO must address. The need to strike the entire R5 in view of the assessment that these requirements are contained in each Transmission Service Provider's tariff will be considered in future revision to this standard. The listing inserted to R2 and R9 provides examples of control measures which are resource and business arrangement neutral that can be arranged or deployed to provide the needed reactive capability. This also applies to the listing already existing in R8.

30. The motivation for this project is to demonstrate that NERC is working to address the directives in Order 693. Do you agree with this?

Summary Consideration:

Many commenters indicate that a number of directives ask the ERO to consider making the directed changes at the next standard revision cycle. We are aware of the language but the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiate was therefore taken to identify and address those directives that appeared to require simple changes.

The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comments.

Some commenters suggest that a project like this could wait until after the new Standards Process Manual (SPM) is approved so that the new SPM can be used to more expeditiously develop the intended standard changes. However, while the new SPM has been adopted by the Board of Trustees, until it is approved by the regulators it cannot be used to support a project like this one. The NERC SC in support of the initiative to illustrate industry responsiveness to directives took the action to deviate from the existing standards development procedure for a good cause. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.

Some commenters indicate that Standard EOP-003 that is included in this project creates a conflict with another project for which a revised EOP-003 is also posted for commenting and balloting. We appreciate this comment, and have removed EOP-003 from consideration for balloting in this project.

Organization	Yes or No	Question 30 Comment
Xcel Energy	No	
IESO	No	A number of the directives included in the package clearly indicates that FERC asked the ERO to consider the directed changes during the next cycle update (or sooner if there are projects to be initiated before the cycle review). Some of the proposed changes, e.g. EOP-003, TOP-005, etc., can wait or be assigned to the existing SDTs. Implementing changes separately from an on-going project runs the risk of contradicting with the SDT's direction of their proposed revisions or may need to be undone at a later stage. We urge the Standards Committee to ensure that adequate coordination among projects to avoid duplicated effort and more importantly that their directions do not run counter of each other and confuse the industry. Response: We recognize that some of the directives ask for consideration for changes at the next standard revision

Organization	Yes or No	Question 30 Comment
		cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiate was therefore taken to identify and address those directives that appeared to require simple changes. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.
IRC Standards Review Committee	No	A number of the directives included in the package clearly indicates that FERC asked the ERO to consider the directed changes during the next cycle update (or sooner if there are projects to be initiated before the cycle review). Some of the proposed changes, e.g. EOP-003, can wait or be assigned to the existing SDTs. Implementing changes separately from an on-going project runs the risk of contradicting with the SDT's direction of their proposed revisions or may need to be undone at a later stage. We urge the Standards Committee to ensure that adequate coordination among projects to avoid duplicated effort and more importantly that their directions do not run counter of each other and confuse the industry. NERC and FERC must work together to resolve reliability issues. However, complex issues are not resolved by simple changes; and simple issues do not deserve to be expedited (over NERC and FERC prioritized projects).The idea of expediting non-impactive requirements or of addressing complex issues helps neither the Industry (who must expend resources on this SAR) nor NERC nor FERC. Response: We recognize that some of the directives ask for consideration for changes at the next standard revision cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiate was therefore taken to identify and address those directives that appeared to require simple changes. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.
National Grid	No	A number of the directives included in the package clearly indicate that FERC asked the ERO to consider the directed changes during the next cycle update (or sooner if there are projects to be initiated before the cycle review). Some of the proposed changes, e.g. EOP-003, TOP-005, etc., can wait or be assigned to the existing SDTs. Implementing changes separately from an ongoing project runs the risk of contradicting the SDT's direction of their proposed

Organization	Yes or No	Question 30 Comment
		revisions, or may need to be undone at a later stage. The Standards Committee should ensure adequate coordination among projects to avoid duplication of effort, and more importantly that their directions do not run counter to each other resulting in industry confusion.NERC, the Regional Entities and their industry partners have been working feverishly to address Order 693 directives, other subsequent directives from various orders, and reliability problems over the last several years. This can be evidenced by looking at a list of NERC's filings to the Commission, their standards development website, participating in the standards development process, and the innumerable hours industry has volunteered through their subject matter experts. Furthermore, the NERC SC has repeatedly authorized NERC to deviate from the standards development process (to shorten it) to expedite development of standards often in response to Commission directives that do not consider the time necessary to develop changes through the Commission approved Reliability Standards Development Process. It is not uncommon for some of these directives to be minor issues that do not address significant reliability gaps. Recently, the industry ballot body also approved a formal modification to the Reliability Standards Development Process that shortens the standards development timeline. Thus, it is unfortunate that NERC feels pressure to produce even more output in standards development with the efforts currently extended by NERC staff, the Regional Entities and industry volunteers. Furthermore, the quality of standards may ultimately suffer, and could be detrimental to reliability if we do not take the necessary time to produce quality standards.This SAR attempted to identify "low hanging fruit" directives from Order 693 that could be acted upon quickly. While at face value this seems like a simple idea, actual execution turned out be challenging as evidenced by lack of coordination between some of the drafting teams. For example, EOP-003 is currently slated to be balloted in two different standards actions simultaneously with changes that do not complement one another. Careful examination of many of these directives reveals there really is not much in the way of low hanging fruit. Seemingly innocuous modifications (such as changing the NERC OC to the ERO in BAL-002) is not as straightforward and insignificant as it appears (please see our comments on that standard above). The electric grid is the largest, most complex machine ever put to use. Reliability standards, likewise, will necessarily be complex. To ensure reliability is not compromised, quality standards must be developed and quality takes time. We believe, unfortunately, that in this attempt to "demonstrate progress", the industry may again be seen as not being able to make "unsubstantial changes" (which are, in fact, substantial). Response: We recognize that some of the directives ask for consideration for changes at the next standard revision cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiate was therefore taken to identify and address those directives that appeared to require simple changes. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank

Organization	Yes or No	Question 30 Comment
		you for the comment. With respect to the EOP-003 standard, we appreciate the industry comments that point to the simultaneous posting issue. For this reason, changes to EOP-003 has been removed fro consideration for balloting along with the others for this project.
Northeast Power Coordinating Council	No	A number of the directives included in the package clearly indicate that FERC asked the ERO to consider the directed changes during the next cycle update (or sooner if there are projects to be initiated before the cycle review). Some of the proposed changes, e.g. EOP-003, TOP-005, etc., can wait or be assigned to the existing SDTs. Implementing changes separately from an ongoing project runs the risk of contradicting the SDT's direction of their proposed revisions, or may need to be undone at a later stage. The Standards Committee should ensure adequate coordination among projects to avoid duplication of effort, and more importantly that their directions do not run counter to each other resulting in industry confusion.NERC, the Regional Entities and their industry partners have been working feverishly to address Order 693 directives, other subsequent directives from various orders, and reliability problems over the last several years. This can be evidenced by looking at a list of NERC's filings to the Commission, their standards development website, participating in the standards development process, and the innumerable hours industry has volunteered through their subject matter experts. Furthermore, the NERC SC has repeatedly authorized NERC to deviate from the standards development process (to shorten it) to expedite development of standards often in response to Commission directives that do not consider the time necessary to develop changes through the Commission approved Reliability Standards Development Process. It is not uncommon for some of these directives to be minor issues that do not address significant reliability gaps. Recently, the industry ballot body also approved a formal modification to the Reliability Standards Development Process that shortens the standards development timeline. Thus, it is unfortunate that NERC feels pressure to produce even more output in standards development with the efforts currently extended by NERC staff, the Regional Entities and industry volunteers. Furthermore, the quality of standards may ultimately suffer, and could be detrimental to reliability if we do not take the necessary time to produce quality standards.This SAR attempted to identify "low hanging fruit" directives from Order 693 that could be acted upon quickly. While at face value this seems like a simple idea, actual execution turned out be challenging as evidenced by lack of coordination between some of the drafting teams. For example, EOP-003 is currently slated to be balloted in two different standards actions simultaneously with changes that do not complement one another. Careful examination of many of these directives reveals there really is not much in the way of low hanging fruit. Seemingly innocuous modifications (such as changing the NERC OC to the ERO in BAL-002) is not as straightforward and insignificant as it appears (please see our comments on that standard above). The electric grid is the largest, most complex machine ever put to use. Reliability standards, likewise, will necessarily be complex. To ensure reliability is not compromised, quality standards must be developed and quality takes time. We believe, unfortunately, that in this attempt to "demonstrate progress", the industry may again be seen as not being able to make "unsubstantial changes" (which are, in fact, substantial). Response: We recognize that some of the directives ask for consideration for changes at the next standard revision

Organization	Yes or No	Question 30 Comment
		cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiate was therefore taken to identify and address those directives that appeared to require simple changes. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment. With respect to the EOP-003 standard, we appreciate the industry comments that point to the simultaneous posting issue. For this reason, changes to EOP-003 has been removed fro consideration for balloting along with the others for this project.
Midwest ISO Standards Collaborators	No	NERC, the Regional Entities and their industry partners have been working feverishly to address Order 693 directives, other subsequent directives from various orders, and reliability problems over the last several years. This can be evidenced by quickly looking at a list of NERC's filings to the Commission, their standards development web site, participating in the standards development process and the innumerable hours industry has volunteered through their subject matter experts. Furthermore, the NERC SC has repeatedly authorized NERC to deviate from the standards development process (to shorten it) to expedite development of standards often in response to Commission directives that do not consider the time necessary to develop changes through the Commission approved reliability standards development process. It is not uncommon for some of these directives to be minor issues that do not address significant reliability gaps. Recently, the industry ballot body also approved a formal modification to the reliability standards development process that shortens the standards development timeline. Thus, it is unfortunate that NERC feels pressure to produce even more output in standards development with the gallant efforts currently extended by NERC staff, the Regional Entities and industry volunteers. Furthermore, we fear that the quality of the standards may ultimately suffer and could be detrimental to reliability if we do not take the necessary time to produce quality standards.This SAR attempted to identify "low hanging fruit" directives from Order 693 that could be quickly acted upon. While at face value, this seems like a simple idea but actual execution turned out be challenging as evidenced by lack of coordination with some of the drafting teams. For example, EOP-003 is currently slated to be balloted in two different standards actions simultaneously with changes that do not complement with one another. Careful examination of many of these directives reveals there really is not much in the way of low hanging fruit. Seemingly innocuous modifications, such as changing the NERC OC to the ERO in BAL-002, are not as straightforward as they appear. (Please see our comments on that standard.) The electric grid is the largest, most complex machine ever put to use. Reliability standards, likewise, will be complex. To ensure reliability is not compromised, quality standards must be developed and quality takes time.

Organization	Yes or No	Question 30 Comment
		Response: The new Standards Prcess Manual (SPM) has been adopted by the Board of Trustees. However, until the SPM is approved by the regulators, it cannot be used to support a project like this one. The NERC SC in support of the initiative to illustrate industry responsiveness to directives took the action to deviate from the existing standards development procedure for a good cause. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.
United Illuminating Company	No	The directives in Order 693 should be addresses via the work plan and review of standards. This exercise does not progress the development of clear standards with a performance base and measurable requirements. A work plan should be develop to prioritze and address the development of new and revised Standards. Response: The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. The NERC SC will soon launch other projects that will provide more adherance to the results-based concept to improve the quality of future standards. The standard development work plan is constantly under review, and adjusted as appropriate, to ensure proper coordination and adequate resource allocation. Thank you for the comment.
US Bureau of Reclamation	No	The process to modify these standards is not following the accept andapproved process. The excuse that "FERC has expressed concern that industryand NERC have been less responsive than desired in providing a timelyresolution to those directives." offers no urgent or compelling reason for thisextraordinary step. It is suggested that NERC utilize the conventional standardmodification process for the changes requested by FERC. Response: Thank you for the comment. We will forward this to the Standards Committee for consideration.
Ameren	No	There is a considerable benefit to follow the normal process of vetting and thoroughly considering all perspectives/aspects. This is evident from number of comments made on this project. Response: The NERC SC, in support of the initiative to illustrate industry responsiveness to directives, took the action to deviate from the existing standards development procedure. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.

Organization	Yes or No	Question 30 Comment
American Electric Power	No	This is a redundant project, and effort should rather be spent in completing the existing project. Response: The NERC SC in support of the initiative to illustrate industry responsiveness to directives took the action to deviate from the existing standards developmen procedure for a good cause. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.
Southern Company Transmission	No	We appreciate the need for speed in this effort to comply with Order 693 directives, however; the language used in many of these changes (including definitions) suffers from ambiguity that is inappropriate in a mandatory standards environment. The measures need to be examined carefully to make sure they align with the changes that have been proposed for the requirements. A thorough review for consistency of terms used is also suggested. We fear that the quality of the standards may ultimately suffer and could be detrimental to reliability if we do not take the necessary time to produce quality standards. Response: The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.
Arizona Public Service Company	Yes	
Central Lincoln	Yes	
Consumers Energy Company	Yes	
Dominion	Yes	
Dynegy Inc.	Yes	
Entergy Services	Yes	
Illinois Municipal Electric Agency	Yes	

Organization	Yes or No	Question 30 Comment
Indiana Municipal Power Agency	Yes	
Kansas City Power & Light	Yes	
PacifiCorp	Yes	
Santee Cooper	Yes	
SDG&E	Yes	
SERC OC Standards Review Group	Yes	
Oklahoma Muncipal Power Authority	Yes	Agree that is the intent of the project. However, in some cases, there is still too much ambiguity to approve the standard as currently drafted. Response: The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.
CECD	Yes	CECD wants to emphasize that (1) the expedited process should be used very selectively in situations where it is truly warranted, not simply to meet deadlines and (2) that a reasonable review and comment period is essential to maintaining the integrity of the standards development process. Response: The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment.
Georgia System Operations Corporation	Yes	None.
Pepco Holdings, Inc. - Affiliates	Yes	Pepco Holdings Affiliates support this effort to show awareness of the Order 693 directives, though we share the

Organization	Yes or No	Question 30 Comment
		concerns of many that several standards needing full review have been only slightly modified to meet the directives. Response: Thank you for the support. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.
Springfield Utility Board	Yes	SUB agrees with the intent and is strongly supportive of this process. Response: Thank you for the support.
NERC Standards Review Subcommittee	Yes	The Midwest Reliability Organization's NERC Standards Review Subcommittee (NSRS) understands the position that the ERO is presently in when faced with the task of incorporating the Commissions directives as written in FERC Order 693. The NSRS agrees that there are "specific" directives that the Commission has presented to the industry and the ERO for inclusion into presently mandatory reliability Standards. The monumental task of providing Reliability Standards that incorporate a word for word placement would only provide an unjust burden on the adequate level of reliability of the Bulk Electric System. Upon the review of FERC Order 693, the NSRS wishes to point out to the ERO that the Commission has stated in paragraph 186 of FERC Order 693 that; 186. Thus, in some instances, while we provide specific details regarding the Commission's expectations, we intend by doing so to provide useful guidance to assist in the Reliability Standards development process, not to impede it. We find that this is consistent with statutory language that authorizes the Commission to order the ERO to submit a modification "that addresses a specific matter" if the Commission considers it appropriate to carry out section 215 of the FPA. In the Final Rule, we have considered commenter's' concerns and, where a directive for modification appears to be determinative of the outcome, the Commission provides flexibility by directing the ERO to address the underlying issue through the Reliability Standards development process without mandating a specific change to the Reliability Standard. Further, the Commission clarifies that, where the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal. Following the Commission's guidance as stated in paragraph 186, the NSRS respectfully submits the above comments that are an equivalent alternative, thus providing an efficient and effective focus within the following mandatory reliability Standards. Response: Thank you for your comments. We will forward this to the Standards Committee for its consideration when assessing projects that address FERC directives. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.
Florida Municipal Power Agency	Yes	We applaud NERC in trying to address many of the FERC directives in Order 693. We remind NERC; however, of the language in the statute, FPA Section 215, that says: "The Commission shall give due weight to the technical

Organization	Yes or No	Question 30 Comment
		expertise of the Electric Reliability Organization ..." NERC ought to question the technical validity of some of the directives and not take FERC directives for granted. In the spirit of being constructive, NERC should offer more technically appropriate directives that address the Commissions concerns, hopefully in a better fashion than what the Commission directs. Response: Thank you for your comments. We will forward this to the Standards Committee for its consideration when assessing projects that address FERC directives.
E.ON U.S.	Yes	While E ON U.S. agrees with what NERC has identified as the motivation for this project, deviation from the standards development process in order to demonstrate work product is not likely to result in the creation of clear, reasonable, and quality standards and requirements. Response: Thank you for the support.
Western Electricity Coordinating Council	Yes	While this same effort could have occured several years ago, I believe that NERC was trying to prioritize modifications based on impact to the BES. I beleive the priorities were for the mose part accurate and I commend NERC for their ongoing effort. Response: Thank you for the support.

31. Are you aware of any conflicts between the proposed standards and any regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement?

Summary Consideration:

Some commenters suggested that the team should apply overall quality improvements more globally. Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.

Some commenters pointed out inconsistencies between standards and other efforts currently underway. However, based on the withdrawal of several changes originally proposed in this project, we believe those conflicts are no longer relevant.

Organization	Yes or No	Question 31 Comment
Ameren	No	
Arizona Public Service Company	No	
Consumers Energy Company	No	
Dominion	No	While we are unaware of specific conflicts, we do see duplication between some reliability requirements and various the terms of tariffs and agreements (as examples; pro-forma Open Access Transmission Tariffs and Interconnection Service Agreements). We do not believe it necessary to have these in more than one place given that, at least in the US, FERC, in most cases, has jurisdiction over all of these and we question which prevails when conflicts arise. Response: Thank you for the comment. We are unable to determine which requirements are in more than one place so we would suggest the commenters to convey to the NERC Standards Manager some examples of such duplications.
Dynegy Inc.	No	
Entergy Services	No	
Florida Municipal Power Agency	No	

Organization	Yes or No	Question 31 Comment
Georgia System Operations Corporation	No	None.
IESO	No	
Illinois Municipal Electric Agency	No	
Kansas City Power & Light	No	
NERC Standards Review Subcommittee	No	
Oklahoma Muncipal Power Authority	No	
PacifiCorp	No	
Pepco Holdings, Inc. - Affiliates	No	
Santee Cooper	No	
SDG&E	No	
SERC OC Standards Review Group	No	
United Illuminating Company	No	
Western Electricity Coordinating Council	No	

Organization	Yes or No	Question 31 Comment
American Electric Power	Yes	AEP does not agree with expanding the scope to the LSE in R5. Furthermore, the existing applicability to the PSE is not a reliability related requirement as this service is provided by the TSP by default. Response: We are unable to relate this comment to this question which deals specifically with conflicts with regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement. Please see the response provided to Q28 (related to P1858) which addresses these comments with respect to the proposed changes to VAR-001.
Central Lincoln	Yes	
Indiana Municipal Power Agency	Yes	EOP-003 is currently in a draft phase under the UFLS project commenting and balloting phase. Response: This standard has been removed from consideration for balloting.
Springfield Utility Board	Yes	SUB's comments on proposed changes to the language on specific standards is reflective of inconsistencies in the original proposed language with regards to reliability, clarity, consisitency. However, with some changes the proposed standards could remove those conflicts. Response: We are unable to relate this comment to the question which deals specifically with conflicts with regulatory function, rule/order, tariff, rate schedule, legislative requirement or agreement. We suggest the commenters to contact the NERC Standards Manager to clarify this comment, if desired.
US Bureau of Reclamation	Yes	The process for modifying the standards was in accordance with the Standard Development Process. Response: Thank you.
Midwest ISO Standards Collaborators	Yes	NERC submitted an informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009. Response: Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.

Organization	Yes or No	Question 31 Comment
National Grid	Yes	NERC submitted an informational filing on August 10, 2009 in response to the Commission's ruling in Order 722. The proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009. Response: Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.
Northeast Power Coordinating Council	Yes	NERC submitted an informational filing on August 10, 2009 in response to the Commission's ruling in Order 722. The proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009. Response: Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach.
Southern Company Transmission	Yes	NERC submitted an informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. Also, the recommended change to VAR-001, R9 seems to violate TPL-002.In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009. Response: Improving standard quality by implementing broad quality improvement measures is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics

Organization	Yes or No	Question 31 Comment
		of the list as indicated in the 2009 filing for this project. In future standard revisions, we will make every attempt to adhere to this proposed approach. We are not sure about the specific conflict between the proposed change to VAR-001, R9 and TPL-002. If the concern is with load shedding in VAR-001, R9, then this is no longer an issue since “load shedding” has been removed from that requirement.

32. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the proposed SAR or standards.

Summary Consideration:

Some commenters expressed a concern that this project was launched despite the fact that FERC has indicated that some of the directed changes should be considered as the standards are due for revision. We recognize this. Standards project priorities are driven by reliability needs, regulatory changes, and compliance issues that have surfaced and continue to surface. Adjustments to the 5-year cycle standards revision plan will be constant because of this. The Standards Committee felt that some of the directives could not be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiative was taken to identify and address those directives that appeared to require simple changes.

Some commenters raised a concern over the continued use of the subrequirement format and the poor quality of some of the existing standards, suggesting that the project should also be aimed at improving standard quality. Improving standard quality beyond that which is needed for the standard to be enforceable and responsive to the directive is outside of the scope of this project. In future standard revisions, we will make every attempt to apply additional improvements that have been identified through other efforts.

Some commenters disagree with the changes made to the Compliance Section on all involved standards, as doing so appears to be outside of the scope for this project. The compliance elements, which are not considered part of the standard, have been updated to reflect the current practices in use today. They do not conflict with the requirements, do not impose any new requirements, and should provide more clarity to entities wishing to comply with the standard. As such, the Response Team believes the updates are both appropriate and within scope.

Some commenters express a concern that approval of the redline changes to address the Order 693 directives may be construed as approving the entire standard. Approval of the individual line item is not construed to be approving the remaining part of the standard. For this reason, balloting is being conducted on a line-item basis, not on a per standard basis.

Organization	Question 32 Comment
Western Electricity Coordinating Council	I still believe that the fill-in-the-blank standards need to be addressed to remove uncertainty in the application of these standards. Response: Thank you for the comment. The scope of this work is to address simple changes to comply with the directives. It does not include reviewing the appropriateness of fill-in-the-blank standards. We will forward this comment to the NERC Standards Committee for its consideration.
Southern Company Transmission	In every standard, the Compliance Monitoring Process has been modified. This was not identified in the scope of the SAR. Thus, these changes appear to exceed the scope of the SAR. Response: Paragraph 330 in Order 693 stipulates that “as identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance

Organization	Question 32 Comment
	monitor." We interpret this to generally apply to all standards as otherwise, there would have been such an explicit directive for every standard covered in Order 693. While the SAR for this project did not explicitly state that all the standards included in the SAR would be changed to address this directive, the proposed work plan to address Paragraph 330 is deemed sufficient to cover modifications to the other standards as well. We do not believe that these changes are outside of the scope for this project.
IESO	None
Springfield Utility Board	SUB appreciates the work put into this process. Response: Thank you for the support.
IRC Standards Review Committee	Unless there is an explicit Order to mandate an immediate change because of an identified active reliability issue then all parties are best served by following the Process that was approved by all parties.Acceptance of any of the proposed changes included in this project is not meant to indicate concurrence with the non-redline text included in the remainder of the Standard. We understand that these are modification to the Version 0 Standards originally filed with FERC and it is widely recognized and understood that these Standard were flawed at the time of adoption and filing.Further, industry approval of these proposed changes must not be construed as approving either the requirement or the standards themselves. Approval must be limited to the ad hoc change itself. Response: We recognize that some of the directives ask for consideration for changes at the next standard revision cycle. However, the standard project priority has been and will continue to be in a state of flux owing to the various reliability needs, regulatory change drivers and compliance issues that have and will continue to surface which will result in the 5-year cycle revision plan needing constant adjustments. The Standards Committee did not think that some of the directives could actually be addressed in a reasonable time frame if they were to wait for the next revision cycle. This initiate was therefore taken to identify and address those directives that appeared to require simple changes. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure the proposed changes, regardless of their perceived simplicity, can be duly debated and vetted. Thank you for the comment. Approval of the individual line item is not construed to be approving the remaining part of the standard. This is why balloting is conducted on a line-item basis, not on a per standard basis.
Dominion	We appreciate the need for speed in this effort to comply with Order 693 directives, however; the language used in many of these changes (including definitions) suffers from ambiguity that is inappropriate in a mandatory standards environment. The measures need to be examined carefully to make sure they align with the changes that have been proposed for the requirements. A thorough review for consistency of terms used is also suggested. NERC submitted an informational filing on

Organization	Question 32 Comment
	August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. Response: Improving standard quality beyond that which is required to be enforceable and to meet the directive is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for VRFs and VSLs. In future standard revisions, we will make every attempt to adhere to this proposed approach. For this set of changes, we have carefully reviewed the Measures, where their respective requirements have been modified, to ensure consistency. We thank you for making this suggestion.
SERC OC Standards Review Group	We appreciate the need for speed in this effort to comply with Order 693 directives, however; the language used in many of these changes (including definitions) suffers from ambiguity that is inappropriate in a mandatory standards environment. The measures need to be examined carefully to make sure they align with the changes that have been proposed for the requirements. A thorough review for consistency of terms used is also suggested. Response: Improving standard quality beyond that whi is required to be enforceable and to meet the directive is outside of the scope of this project,and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for VRFs and VSLs. In future standard revisions, we will make every attempt to adhere to this proposed approach. For this set of changes, we have carefully reviewed the Measures, where their respective requirements have been modified, to ensure consistency. We thank you for making this suggestion
SDG&E	[1] For FAC-002, there are "subregional processes" at WECC region. For instance, for generator interconnection study, utilities within CAISO are doing study work for CAISO as subcontractor. The document requests should apply only CAISO. [2] For MOD-17, the standard should emphasize each entity has one designated function or group to provide "information". Current wording requests "load serving entity", "planning authority", "transmission planner", and "resource planner" shall each provide..... Response: We are unable to understand your concern since the proposed changes to FAC-002 invlove Requirement R1.4 and the Compliance Enforcement Authority and Process only, none of which touched on applicable entities. Please contact the NERC Standards Manager to clarify your concern as appropriate. MOD-017 has been removed from consideration for balloting. You comments on MOD-017 will be retained for future

Organization	Question 32 Comment
	consideration.
Illinois Municipal Electric Agency	Given the current avalanche of Reliability Standards Under Development, it is impossible for most municipal entities or a Joint Action Agency to adequately assess the implications of the numerous proposed revisions to existing reliability standards and proposed new reliability standards. A moratorium on standards development needs to be established until existing standards have gone through the results-based review. Response: We recognize the large volume of work ongoing today, and the staffing challenges that it presents. Unfortunately, it is not feasible to impose such a moratorium; progress to improve reliability must continue in tandem with our results-based initiatives.
Midwest ISO Standards Collaborators	In every standard, the Compliance Monitoring Process has been modified. This was not identified in the scope of the SAR. Thus, these changes appear to exceed the scope of the SAR. Response: Paragraph 330 in Order 693 stipulates that “as identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.” We interpret this to generally apply to all standards as otherwise, there would have been such an explicit directive for every standard covered in Order 693. While the SAR for this project did not explicitly state that all the standards included in the SAR would be changed to address this directive, the proposed work plan to address Paragraph 330 is deemed sufficient to cover modifications to the other standards as well. We do not believe that these changes are outside of the scope for this project.
Indiana Municipal Power Agency	In general, it seems like some new terms need to be defined or added to the functional model, such as Regional Entity and ERO. These changes may start here and need to be carried out through all NERC standards. Response: Thank you. We will forward this comment to the Functional Model Working Group.
Ameren	Since it is widely acknowledged that sub requiremnts are really sub-parts of the main requirement and not each individual requirement, the sub-requiremnts should be removed as part of these effort. The reason for our comment is supported by the new Reliability Standrad Template available on the NERC site. Response: Improving standard quality beyond that which is required to be enforceable and to meet the directive is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system. However, this suggestion will be considered in other standard projects.
Disturbance and Sabotage Reporting Drafting Team	The DSR SDT requests that the Project 2010-12, Order 693 Directives SDT remove EOP-004 from its project. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) is currently revising the requirements of EOP-004. The timing of revisions, with two teams proposing revisions to the same standard in the same time frame, may lead to

Organization	Question 32 Comment
	stakeholder confusion and result in filing of competing standards with the FERC. The DSR SDT has many concerns with the proposed revisions to EOP-004 and the team is working to correct the deficiencies of the requirements. Examples of these deficiencies include 1) use of the word "promptly" in R2 and R3 (ambiguous); 2) having LSE an applicable entity (R3) since an LSE does not necessarily own assets; and 3) Continued use of the RRO in the requirements.The DSR SDT does not consider the proposed revisions to be "low hanging friut". The proposed revisions do address the explicit directives (paragraphs 612 and 615), but fail to provide needed clarity to the requirements. The DSR SDT requests that the Project 2010-12, Order 693 Directives SDT remove EOP-004 from its project. Response: Thank you. EOP-004 has been removed from consideration for balloting due to the reasons cited, and after consideration of other comments.
Georgia System Operations Corporation	The proposed SAR and standards resulting from the abbreviated development process are excellent examples of the value of the approved Standards Development Process and the inadvisability of taking shortcuts on that process. We believe that these revisions would have been much better implemented through the approved process and request that the ERO and the Standards Committee refrain from using an abbreviated process in the future. Response: Thank you for the support. The NERC SC recently discussed the use of expedited processes included in the approved standards development process. We believe the SC will continue to exercise its discretion on the best approach to take in response to directives or other urgent issues. The experience with this project suggests that proper coordination and adequate debates would need much more time to ensure that any proposed changes, regardless of their perceived simplicity, can be duly debated and vetted.
E.ON U.S.	The section format / lettering of the standards is inconsistent. For example, BAL-002-1 and others have Introduction labeled as section "A" and Requirements as section "B" while others do not have a label for Introduction and have section "A" as Requirements. E ON U.S. suggests that a consistent format be used for all standards.In addition to the comments provided herein, E ON U.S. generally supports the comments submitted by both Midwest ISO and PJM Interconnection. Response: The purpose of this project is to expeditiously address outstanding directives with a limited amount of changes, leaving the objective of improving standard quality to future projects when the affected standards are due for revision. In future standard revisions, we will make every attempt to ensure consistent standard format/structure.
National Grid	There is a potential conflict with existing standards under development. Unless there is an explicit Order to mandate an immediate change because of an identified active reliability issue then all parties are best served by following the Process that was approved by all parties. Response: Thank you. All potential conflicts have been identified either at the pre-posting stage or during this commenting/balloting stage. Standard changes that could create a conflict with existing standard projects have been identified by the affected standards' standard drafting teams and the Response Team. We believe all conflicts have been duly

Organization	Question 32 Comment
	addressed.
Northeast Power Coordinating Council	There is a potential conflict with existing standards under development. Unless there is an explicit Order to mandate an immediate change because of an identified active reliability issue then all parties are best served by following the Process that was approved by all parties.Acceptance of any of the proposed changes included in this project is not meant to indicate concurrence with the non-redline text included in the remainder of the standard. These are modifications to the Version 0 standards originally filed with FERC, and it is widely recognized and understood that these Standards were flawed at the time of adoption and filing. Response: Thank you. All potential conflicts have been identified either at the pre-posting stage or during this commenting/balloting stage. Standard changes that could create a conflict with existing standard projects have been identified by the affected standards' standard drafting teams and the Response Team. We believe all conflicts have been duly addressed. Approval of the individual line item is not construed to be approving the remaining part of the standard. This is why balloting is conducted on a line-item basis, not on a per standard basis.
Entergy Services	We appreciate the need for speed in this effort to comply with Order 693 directives, however; the language used in many of these changes (including definitions) suffers from ambiguity that is inappropriate in a mandatory standards environment. The measures need to be examined carefully to make sure they align with the changes that have been proposed for the requirements. A thorough review for consistency of terms used is also suggested.NERC submitted an informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be and should not be done in the changes being undertaken to modify the standards at this time.In most of the proposed standards, NERC has deviated from their planned course of action communicated to the Commission in this filing on August 10, 2009. Response: Improving standard quality beyond that which is required to be enforceable and to meet the directive is outside of the scope of this project, and therefore we have not adopted the use of a numbered or bulleted list system based on the characteristics of the list as indicated in the 2009 filing for VRFs and VSLs. In future standard revisions, we will make every attempt to adhere to this proposed approach.

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Implementation Plan for Standards:

- BAL-002-1 — Disturbance Control Performance;
- BAL-005-1 — Automatic Resource Control;
- EOP-001-2 — Emergency Operations Planning;
- EOP-002-3 — Capacity and Energy Emergencies;
- EOP-003-2 — Load Shedding Plans;
- EOP-004-2 — Disturbance Reporting;
- FAC-002-1 — Coordination of Plans For New Generation, Transmission, and End-User Facilities;
- MOD-017-1 — Aggregated Actual and Forecast Demands and Net Energy for Load;
- MOD-019-1 — Reporting of Interruptible Demands and Direct Control Load Management;
- MOD-020-1 — Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators;
- MOD-021-2 — Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts;
- PRC-004-2 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations; and
- VAR-001-2 — Voltage and Reactive Control

Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), approved or in progress, that must be implemented before these standards can be implemented.

New Definitions
Automatic Resource Control (ARC)

Modified Definitions
Automatic Generation Control (AGC)
Demand-Side Management (DSM)
Operating Reserve — Spinning
Operating Reserve — Supplemental
Regulating Reserve

Retired Definitions
Spinning Reserve

Modified Standards
BAL-002-1 supersedes BAL-002-0.
BAL-005-1 supersedes BAL-005-0.
EOP-001-2 supersedes EOP-001-1.
EOP-002-3 supersedes EOP-002-2.
EOP-003-2 supersedes EOP-003-1.
EOP-004-2 supersedes EOP-004-1.
FAC-002-1 supersedes FAC-002-0.
MOD-017-1 supersedes MOD-017-0.
MOD-019-1 supersedes MOD-019-0.
MOD-020-1 supersedes MOD-020-0.
MOD-021-2 supersedes MOD-021-1.
PRC-004-2 supersedes PRC-004-1.
VAR-001-2 supersedes VAR-001-1.

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Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

	Balancing Authority	Transmission Planner	Transmission Owner	Transmission Operator	Resource Planner	Load-Serving Entity	Planning Authority	Distribution Provider	Reserve Sharing Group	Regional Reliability Organization	Generator Owner	Generator Operator	Purchasing Selling Entity	Reliability Coordinator
BAL-002-1	X								X	X				
BAL-005-1	X			X		X						X		
EOP-001-2	X			X										
EOP-002-3	X					X								X
EOP-003-2	X			X										
EOP-004-2	X			X		X		X		X		X		X
FAC-002-1		X	X			X	X	X			X			
MOD-017-1		X			X	X	X							
MOD-019-1		X			X	X	X							
MOD-020-1		X			X	X								
MOD-021-2		X				X								
PRC-004-2		X	X	X		X					X			
VAR-001-2				X		X							X	

Proposed Effective Dates

For MOD-021-1
The first day of the first calendar quarter after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees' adoption.

For BAL-005-1, EOP-001-2, EOP-002-3, EOP-004-2, FAC-002-1, and VAR-001-2
The first day of the first calendar quarter, six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

For BAL-002-1, EOP-003-2, MOD-017-1, MOD-019-1, MOD-020-1, and PRC-004-2
The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

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Standards Announcement

Ballot Pool and Pre-ballot Window (with Comment Period)
Project 2010-12: Order 693 Directives

Now available at: http://www.nerc.com/filez/standards/Project2010-12_Order-693_Directives.html

On March 18, 2010, FERC issued several orders and notices of proposed rulemakings pertaining to standards development activities and processes, suggesting a lack of progress in responding to directives from Order 693 as well in the timeliness of standards development in general. At the May 2010 NERC Board meeting, Gerry Cauley, NERC's President, also expressed these concerns, indicating that the resolution to these concerns is one of NERC's top priorities in the near term. As a result, the Standards Committee has authorized deviations from the normal standards development process for this Order 693 Directives project, as well as other projects that have been through significant stakeholder review through the development process, to demonstrate that the NERC enterprise is responsive to FERC directives.

Project 2010-12: Order 693 Directives

In Order No. 693, the Commission issued many directives to modify NERC Reliability Standards.

Several of the directives appear to be less controversial than others. In an effort to be more responsive, the Standards Committee has approved having NERC assemble a team of experts to assist in reviewing the directives and identifying those which had a significant chance of being non-controversial; i.e., could be modified, balloted, and filed in a very short amount of time.

NERC and its team of experts have identified 37 directives related to 14 standards that seem to be relatively non-controversial. Working with input from various parts of the industry, a set of proposed changes to meet the directives has been developed. In order to expedite this project, the Standards Committee has approved an accelerated schedule.

The Standards Committee approved the following deviations from the standards development process:

- Post the SAR and proposed revisions for a formal shortened comment period (June 18–July 13, 2010)
- Form the ballot pool during the first 15 days of the comment period (June 18–July 2, 2010)
- Conduct an initial 10-day ballot on a line-item basis (July 3–13, 2010)
- Require the withdrawal from balloting any item that has significant disagreement from stakeholders as evidenced in comments and ballot results
- Allow modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard (recirculation ballot July 20–30, 2010)

Ballot Pool (through July 2, 2010)

Registered Ballot Body members may join the ballot pool **until 8 a.m. Eastern on July 2, 2010** 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 standards will automatically be able to vote on the associated violation risk factors (VRFs) and violation severity levels (VSLs). The votes for the VRFs and VSLs will be considered "non-binding."

The voting will take place using a single form with "line item" voting for each proposed change. Changes that meet with strong disagreement from stakeholders will be removed from the second ballot. NERC recognizes that balloting a series of changes using our current ballot software may be challenging, and therefore we are currently testing an alternate approach to simplify the balloting process.

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-2010-12_Order693_in@nerc.com

Comment Period (through July 13, 2010)

Please use this comment form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net.

The documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site http://www.nerc.com/filez/standards/Project2010-12_Order-693_Directives.html

Project Background

This posting represents the first formal review of the standard authorization request (SAR) related to this effort as well as the proposed changes. The directives have been summarized in the tables in the comment form. Each table addresses a set of directives associated with a standard. Following each table is a set of questions seeking feedback on the proposed modifications. In order to be responsive to these directives, please consider the following when commenting on these standards:

- Does the change harm reliability?
- Does the change improve reliability?
- Does the change neither harm nor improve reliability, but make the standard (or the Commission's expectations regarding the standard) clearer?
- Are there modifications you can propose that would make the changes more acceptable and still be responsive to the Commission's directives?

NERC and its team of experts are seeking comments on these draft standards. It is the goal of this project to focus on items that appear to be widely supported. If you can identify changes that will assist in the acceptance of these changes, please feel free to suggest them.

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

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Standards Announcement

Initial Ballot Windows Open
July 2–13, 2010

Project 2010-12: Order 693 Directives

Initial ballot windows for the proposed standards from the Order 693 Directives are now open **until 8 p.m. Eastern on July 13, 2010**.

Instructions

Members of the ballot pool associated with this project will receive a separate e-mail with a link to the set of ballots and specific instructions for using the new balloting approach. Changes related to each paragraph from Order 693 are being balloted separately and the ballots are significantly different in appearance compared to previous ballots.

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

On March 18, 2010, FERC issued several orders and notices of proposed rulemakings pertaining to standards development activities and processes, suggesting a lack of progress in responding to directives from Order 693 as well in the timeliness of standards development in general. At the May 2010 NERC Board meeting, Gerry Cauley, NERC's President, also expressed these concerns, indicating that the resolution to these concerns is one of NERC's top priorities in the near term. As a result, the Standards Committee has authorized deviations from the normal standards development process for this Order 693 Directives project, as well as other projects that have been through significant stakeholder review through the development process, to demonstrate that the NERC enterprise is responsive to FERC directives.

In Order No. 693, FERC issued many directives to modify NERC Reliability Standards.

Several of the directives appear to be less controversial than others. In an effort to be more responsive, the Standards Committee has approved having NERC assemble a team of experts to assist in reviewing the directives and identifying those which had a significant chance of being non-controversial; i.e., could be modified, balloted, and filed in a very short amount of time.

NERC and its team of experts have identified 34 directives related to 13 standards that seem to be relatively noncontroversial. Working with input from various parts of the industry, a set of proposed changes to meet the directives has been developed. In order to expedite this project, the Standards Committee has approved an accelerated schedule.

The Standards Committee approved the following deviations from the standards development process:

- Post the SAR and proposed revisions for a formal shortened comment period (June 18–July 13, 2010)
- Form the ballot pool during the first 15 days of the comment period (June 18–July 2, 2010)
- Conduct an initial 10-day ballot on a line-item basis (July 2–13, 2010)
- Require the withdrawal from balloting any item that has significant disagreement from stakeholders as evidenced in comments and ballot results
- Allow modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard (recirculation ballot July 20–30, 2010)

The directives have been summarized in the tables in the balloting form. Each table addresses a set of directives associated with a standard. Following each table is a set of questions seeking feedback on the proposed modifications. In order to be responsive to these directives, please consider the following when voting on these standards:

- Does the change harm reliability?
- Does the change improve reliability?
- Does the change neither harm nor improve reliability, but make the standard (or the Commission's expectations regarding the standard) clearer?
- Are there modifications you can propose that would make the changes more acceptable and still be responsive to the Commission's directives?

It is the goal of this project to focus on items that appear to be widely supported. If you can identify changes that will assist in the acceptance of these changes, please feel free to suggest them.

Project page: http://www.nerc.com/filez/standards/Project2010-12_Order-693_Directives.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

Initial Ballot Results — Project 2010-12: Order 693 Directives

Ballot Results	
Ballot Name:	Project 2010-12: Order 693 Directives[1]
Ballot Period:	July 2–14, 2010
Ballot Type:	Initial
Total # Votes:	217
Total Ballot Pool:	295
Quorum:	73.55%[2]
Weighted Segment Vote:	See below (multiple ballots)
Ballot Results:	Some changes will proceed to recirculation ballots, while others have been withdrawn.

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
321	The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary.	60.96%	BAL-002-1	DELETED SENTENCES IN R4.2 AND R6.2 THAT ALLOWED CHANGES WITH OC APPROVAL.
321	As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.		BAL-002-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION
330	We direct the ERO to submit a modification to BAL-002-0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.	49.90%	BAL-002-1	WITHDRAWN FROM BALLOT

[1] Conducted as multiple ballots

[2] Though the initial ballots did not reach quorum, the Standards Committee has agreed (for this project only) to move proposed changes to recirculation ballots, recognizing the extraordinary effort already put forward by stakeholders to assist in getting these revisions to the NERC Board of Trustees and the challenges some stakeholders faced in accessing the ballots.

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
335	Accordingly, the Commission directs the ERO to explicitly allow DSM as a resource for contingency reserves, and clarifies that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.	41.86%	BAL-002-1	WITHDRAWN FROM BALLOT
1232	We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.	48.99%	BAL-002-1	WITHDRAWN FROM BALLOT
404	The Commission clarifies that its direction to the ERO in this section is for it to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct control load management as regulating reserves, subject to the clarifications provided in this section.	62.16%	BAL-005-1	WITHDRAWN FROM BALLOT
415	Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission's proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the	61.59%	BAL-005-1	WITHDRAWN FROM BALLOT

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
	ERO's Work Plan. 410. Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area. 411. FirstEnergy states that Requirement R17 should include only "control center devices" instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term "check" in Requirement R17 needs to be clarified.			
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management	54.82%	BAL-005-1	WITHDRAWN FROM BALLOT

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using nonfarm service		BAL-005-1	WITHDRAWN FROM BALLOT
565	The Commission agrees with ISO-NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the “for consideration” elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.	78.45%	EOP-001-2	WITHDRAWN FROM BALLOT – ALREADY ADDRESSED IN PREVIOUS VERSION OF STANDARD.
571	As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that “insufficient transmission capability” could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.	55.39%	EOP-001-2	WITHDRAWN FROM BALLOT
577	A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As	96.05%	EOP-002-3 (No changes to standard)	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION – BELIEVED TO ALREADY BE ADDRESSED IN IRO-006-4, SO NO CHANGES TO STANDARD NEEDED.

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
	such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.			
582	Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. 579. ISO-NE states that Requirement R2 essentially requires the same actions covered by ISO-NE Operating Procedure No. 4. ISO-NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO-NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO-NE procedures. ISO-NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.	77.21%	EOP-002-3	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION FOR THIS PORTION OF PARAGRAPH 582. MODIFIED MEASURE M5 PER COMMENTERS SUGGESTIONS.
582	Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.		EOP-002-3	MODIFIED MEASURE M5 PER COMMENTERS SUGGESTIONS.
573	Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.	62.28%	EOP-002-3	WITHDRAWN FROM BALLOT

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
601	We also note that APPA raise(s) issues regarding coordination of trip settings and automatic and manual load shedding plans. The Commission directs the ERO to consider these comments in future modification to the Reliability Standard through the Reliability Standards development process. 598 In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners.	36.13%	EOP-003-2	WITHDRAWN FROM BALLOT
603	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-003-1 through the Reliability Standards development process that requires periodic drills of simulated load shedding.	14.86%	EOP-003-2	WITHDRAWN FROM BALLOT
612	APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.	55.97%	EOP-004-2	WITHDRAWN FROM BALLOT

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
615	The Commission declines to address Xcel's concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process. 608. Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations. Further, Xcel states that the requirement in Requirement R3.4 for a final report within 60 days may not be feasible given the current WECC process, which among other things, requires the creation of a group to prepare the report and a 30-day posting of a draft report before it becomes final. Xcel also states that if the ultimate purpose of the report is to provide information to avoid a recurrence of a system disturbance, then the Reliability Standard should be revised to require the distribution of the report to similarly situated entities.	65.98%	EOP-004-2	WITHDRAWN FROM BALLOT
693	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.	81.60%	FAC-002-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
1249	The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.	33.23%	MOD-017-1	WITHDRAWN FROM BALLOT
1250	We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.	33.20%	MOD-017-1	WITHDRAWN FROM BALLOT
1251	The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves	35.22%	MOD-017-1	WITHDRAWN FROM BALLOT

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
	load forecasts themselves.			
1252	The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.	38.16%	MOD-017-1	WITHDRAWN FROM BALLOT
1255	We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.	66.48%	MOD-017-1	WITHDRAWN FROM BALLOT
1276	The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission’s concern.	47.00%	MOD-019-1	WITHDRAWN FROM BALLOT

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
1277	We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.	34.53%	MOD-019-1	WITHDRAWN FROM BALLOT
1287	We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	53.58%	MOD-020-1	WITHDRAWN FROM BALLOT
1300	The Commission directs the ERO to modify the title and purpose statement to remove the word "controllable." We note that no commenter disagrees.	92.94%	MOD-021-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION
1469	Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.	52.23%	PRC-004-2	REFERENCES TO RRO IN R3 AND M3 CORRECTED. LSE AND TOP HAVE BEEN REMOVED. OTHERWISE, NO CHANGE FROM PREVIOUSLY BALLOTED VERSION.
1469	We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.		PRC-004-2	THESE CHANGES REMOVED FROM THE STANDARD. LSE AND TOP HAVE BEEN REMOVED.

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
1858	The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	69.22%	VAR-001-2	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION
1879	The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1.	64.35%	VAR-001-2	LOAD SHEDDING REMOVED FROM R2, R5, AND R9.
1879	While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements. 1878. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.		VAR-001-2 (No changes to standard)	LOAD SHEDDING REMOVED FROM R2, R5, AND R9. OTHERWISE, NO CHANGE FROM PREVIOUSLY BALLOTED VERSION – RESPONSE TEAM BELIEVES NO CHANGES ARE NEEDED TO ADDRESS SOCAL EDISON AND SMA COMMENTS

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Order 693 Directives (Project 2010-12)
Date of Initial Ballot: July 2, 2010 through July 14, 2010

Summary Consideration: Stakeholder comments were used to determine whether each proposed modification should move forward to a second ballot and to determine, if the modification was supported by stakeholders, whether additional modifications would improve the proposed language. The following table summarizes the disposition of the proposed modifications.

On the following pages, for each ballot, the specific comments submitted and the team's consideration of those comment have been provided.

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, Herb Schrayshuen, at 609-452-8060 or at Herb.Schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Standard	Directive Reference	Did Comments Indicate the Modification Should Move Forward?	If Yes, Were Changes Made?
BAL-002-1	P330 P335 P1232	No – the proposed modifications were removed from the standard	
	P321	Yes	Modified R4.2 and R6.2
BAL-005-1	P404 P415 P420	No – the proposed modifications were removed from the standard	
EOP-001-2	P571	No – the proposed modifications were removed from the standard	
EOP-002-3	P573	No – the proposed modifications were removed from the standard	
	P577	No – no modifications were proposed; stakeholders agreed the directive was addressed in IRO-006-4	
	P582	Yes	Modified M5
EOP-003-2	P601 P603	No – the proposed modifications were removed from the standard	
EOP-004-2	P612 P615	No – the proposed modifications were removed from the standard	
FAC-002-1	P693	Yes	No modifications
MOD-017-1	P1249 P1250	No – the proposed modifications were removed from the standard	

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Standard	Directive Reference	Did Comments Indicate the Modification Should Move Forward?	If Yes, Were Changes Made?
	P1251 P1252 P1255		
MOD-019-1	P1276 P1277	No – the proposed modifications were removed from the standard	
MOD-020-1	P1287	No – the proposed modifications were removed from the standard	
MOD-021-1	P1300	Yes	No modifications
PRC-004-2	P1469	Partial – changes to expand applicability to include LSEs and TOPs were removed; Changes to replace the RRO with RE were retained	Modified M1, M2, M3
VAR-001-2	P1858 P1879	Yes	Modified R2, R5, R9

Contents

Summary Consideration for changes related to P321:
Several commenters suggested that instead of replacing "NERC Operating Committee" with "ERO," the standard could be improved in an alternate fashion simply by removing the provisions for unilateral adjustment of these time periods by any group or entity. The Response Team agreed and removed the last two sentences of R4.2 and R6.2, which now read as follows:

R4.2 The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

R6.2 The default Contingency Reserve Restoration Period is 90 minutes.

Voter	Entity	Segment	P 321	Comments
Jason Shaver	ATC	1	Abstain	
Allen Mosher	APPA	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	

Voter	Entity	Segment	P 321	Comments
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Steven M. Jackson	MEAG	3	Abstain	
Steven Grego	MEAG Power	3	Abstain	
Saurabh Saksena	National Grid	1	Abstain	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Michael T. Quinn	Oncor Electric Delivery	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Daniel Baerman	San Diego G&E	5	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	

Voter	Entity	Segment	P 321	Comments
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Richard J. Mandes	Alabama Power Co.	3	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Kirit S. Shah	Ameren Services	1	Approve	
Mark Peters	Ameren Services	3	Approve	
Sam Dwyer	Ameren	5	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Brenda S. Anderson	BPA	6	Approve	

Voter	Entity	Segment	P 321	Comments
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
Brian Conroy	Central Maine Power Co.	1	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Thomas E Washburn	FMPP	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	

Voter	Entity	Segment	P 321	Comments
Anthony L Wilson	Georgia Power Co.	3	Approve	
Gwen S Frazier	Gulf Power Co.	3	Approve	
Rex A Roehl	Indeck Energy Services, Inc.	5	Approve	
Kim Warren	IESO	2	Approve	
Charles Locke	KCPL	3	Approve	
Michael Gammon	KCPL	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
Don Horsley	Mississippi Power	3	Approve	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	

Voter	Entity	Segment	P 321	Comments
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Glen Reeves	Salt River Project	5	Approve	

Voter	Entity	Segment	P 321	Comments
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	

Voter	Entity	Segment	P 321	Comments
Brandy A Dunn	WAPA	1	Approve	
Louise McCarren	WECC	10	Approve	
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
David F. Lemmons	Xcel Energy, Inc.	6	Approve	
Gregory L Pieper	Xcel Energy, Inc.	1	Approve	
Liam Noailles	Xcel Energy, Inc.	5	Approve	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	

Voter	Entity	Segment	P 321	Comments
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Scott Peterson	San Diego G&E	3	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Greg C Parent	Manitoba Hydro	3	Disapprove	- Changing “NERC” to “ERO” is not valid in Canadian jurisdictions. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concerns.
Randall McCamish Frank Gaffney Walt Gill	City of Vero Beach Florida Municipal Power Agency Lake Worth Utilities	1 4 1	Disapprove Disapprove Disapprove	A better solution would simply be to strike the sentence "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee", by doing so, any change to the 15 minutes or 90 minutes would be done through the ERO as part of the stakeholder process, meeting the intent of the directive that the ERO ought to do it, while retaining the stakeholder process. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as

Voter	Entity	Segment	P 321	Comments
Larry E Watt	Lakeland Electric	1	Disapprove	suggested.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	AStrike the sentence "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee" allowing this to go through the ERO via the stakeholder process. This would meet the intent of the directive that the ERO should be involved while retaining the stakeholder process. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
Eric Egge	Black Hills Corp	1	Disapprove	BHC recommends an equally effective alternative solution by striking the last sentence of R4.2 and R6.2 to remove the NERC Operating Committee reference. The reference to the NERC OC pre-dates the mandatory enforcement era and any change in the time period should come through the NERC standards development process and applicable to all parties or for unique situations through the entity variance request. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
Daniel Prowse	Manitoba Hydro	6	Disapprove	Changing “NERC” to “ERO” is not valid in Canadian jurisdictions Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concerns.
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Danny McDaniel	Cleco Power LLC	1	Disapprove	Cleco disagrees with inserting the ERO in place of the NERC Operating Committee in BAL-002 as the language would allow NERC to bypass any stakeholder process, or any required ERO process for that matter, for modifying the 15-minute DCS Recovery Period to a timing not vetted in the industry. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concerns.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments." Response: Please see response to Doug Hohlbaugh.
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form Response: Please see the appropriate Consideration of Comments for response.

Voter	Entity	Segment	P 321	Comments
Donald Gilbert	JEA	5	Approve	Demand-side should be hyphenated Response: The language has been removed based on comments on other directives.
Greg Lange	Public Utility District No. 2 of Grant County	3	Disapprove	Disturbance recovery should remain a part of the standards process. NERC OC should be deleted and nothing put in its place. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
David A. Lapinski	Consumers Energy	3	Disapprove	Establishing quantitative criteria for the Disturbance Recovery Period requires broadly based and in-depth analysis, which can be obtained only through full industry input. In R4.2 the change to allow the ERO to change the value is inappropriate. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concern.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE recommends an equally effective alternative solution by striking the last sentence of R4.2 and R6.2 to remove the NERC Operating Committee reference. The reference to the NERC OC pre-dates the mandatory enforcement era and any change in the default Disturbance Recovery time period should come through the NERC standards development process and applicable to all parties or for unique situations through an entity variance request. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested. In regards to the second request within paragraph 321 regarding the FERC directed change from the term RRO to RE in Section D, FE supports this change, however, only one vote was permitted for the entire paragraph 321 items. FE is voting negative on the overall paragraph 321 item per our above comments.In the re-circulation ballot consider allowing unique ballots for each “directive” or “topic for consideration”, not just by the paragraph number. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concerns.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Thomas J. Bradish	RRI Energy	5	Disapprove	In R4.2 and R6.2 the sentence containing the proposed change (last sentence)

Voter	Entity	Segment	P 321	Comments
Trent Carlson	RRI Energy	6	Disapprove	should be deleted from the standard. Any modifications to the periods in these requirements should follow the normal RSDP. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
Daniel Herring	Detroit Edison Co.	4	Disapprove	Neither the ERO or the NERC Operating Committee should have a role in BAL-002. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concerns.
Harold Taylor, II	GTC	1	Approve	None Response: No response required.
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 321 - ERO Replacing the NERC Operating Committee: Though the NERC Operating Committee and its subcommittees provide the technical forums for discussion of reliability issues associated with system operations and the NERC Standards in place to support reliable operation, Duke Energy believes that the last sentence of 4.2 and 6.2 should be removed rather than revised to insert the ERO. The reference to the NERC Operating Committee pre-dates the mandatory enforcement era; any proposed change to the duration of the DCS Recovery Period should now come through the NERC standards development process. The Balancing Authority Controls SDT under Project 2007-05 and the Reliability-Based Control SDT under Project 2007-18 have worked on different aspects of BAL-002 within their scope, however none of the research to date has indicated a reliability concern with the 15-minute DCS Recovery Period that would support the NERC Operating Committee or the ERO having such a role in BAL-002 today. In addition, wishing no disrespect to NERC staff but reinforcing the stakeholder process under the RSDP, we disagree with inserting the ERO in place of the NERC Operating Committee in BAL-002 as the language would allow NERC to bypass any stakeholder process, or any required ERO process for that matter, for modifying the 15-minute DCS Recovery Period to a timing not vetted in the industry. If the language is not removed, we believe the existing language,

Voter	Entity	Segment	P 321	Comments
				including the reference to the NERC Operating Committee, should remain in BAL-002 until addressed in the revisions being developed by the BACSDT, which already has the FERC's directive within its scope. Overall we believe that the FERC had the opinion that the NERC Operating Committee should not have the role depicted in BAL-002-0; by removing the related text, that concern would be addressed.Background: Policy 1 language supported that the Resources Subcommittee played a role in the review of Interconnection performance and could propose a change to the 15-minute period for an Interconnection based upon its analysis or analysis provided by others. If a change had been approved, the Resources Subcommittee would have taken the analysis to the NERC Operating Committee and it would have been up to the Operating Committee then to discuss the merits of the analysis and implications of the change. Approval of the Resources Subcommittee and NERC Operating Committee were required as indicated in Section 2.2.2 of Policy 1 from October 8, 2002:NERC Policy 1 Version 2 NERC BOT Approved October 8, 2002:"Section 2.2.2. DISTURBANCE RECOVERY PERIOD. The default DISTURBANCE RECOVERY PERIOD is 15 minutes after the start of a REPORTABLE DISTURBANCE. This period may be adjusted to better suit the needs of an INTERCONNECTION based on analysis approved by the NERC Resources Subcommittee and the NERC Operating Committee."As the Policy 1 was converted to the first set of BAL Standards, the Resources Subcommittee was removed from the language now in BAL-002-0 R4.2 as it was a subordinate group to the NERC Operating Committee and the NERC Operating Committee had the authority to approve a change no matter of the position of its subcommittee.BAL-002-0 NERC BOT Approved February 8, 2005 - Effective Date: April 1, 2005"R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee." Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested. Paragraph 321 - RE replacing the RRO: Our NO vote is related to the proposed change discussed above. We agree with the change for the RE but with the following question and comment: as the Standards do not point to entities, but to functions providing specific tasks as described in the Functional Model, is it

Voter	Entity	Segment	P 321	Comments
				appropriate to insert Regional Entity in place of Regional Reliability Organization (RRO) when the current functional model refers to the Reliability Assurer? We believe consistency is needed - either use Regional Entity in the Standards and the Functional Model, or reference Reliability Assurer in Standards and the Functional Model. Response: The Functional Model defines roles and functions, but not necessarily titles. We believe that the use of the term "Regional Entity" as the Compliance Enforcement Authority is appropriate.
John Tolo	Tucson Electric Power Co.	1	Disapprove	Reinforcing the stakeholder process under the RSDP, I disagree with inserting the ERO in place of the NERC Operating Committee in BAL-002 as the language would allow NERC to bypass any stakeholder process, or any required ERO process for that matter, for modifying the 15-minute DCS Recovery Period to a timing not vetted in the industry. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concern.
Lee Schuster	Florida Power Corporation	3	Disapprove	Section 4 Applicability, subsection 4.3 should be changed from Regional Reliability Organization to Regional Entity Response: While the Compliance Enforcement Authority role is performed by the delegated authority provided to the Regional Entity, it believed that the actions required in this standard are provided by the RRO.
James Eckelkamp	Progress Energy	6	Disapprove	
Wayne Lewis	Progress Energy Carolinas	5	Disapprove	
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	strike sentence 'this period may be adjusted to better suit the needs of an interconnection based on anlysis approved by the NERC OC Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	Taken in isolation the concept of changing NERC OC to ERO would be reasonable. Taken in conjunction with the entire standard the change becomes a de facto acceptance of the two requirements. Two requirements that require significant review and change. The SAR requestor misses a key point in R4.2 and R6.2 and that is the fact that the requirement itself is about making changes to the DCS recovery period itself. Who makes the change is secondary to the fact that the changes are being allowed at any time without any clarity about implementation and compliance. In a pre-mandatory environment, such

Voter	Entity	Segment	P 321	Comments
				changes could be made as needed. However, both R4.2 and R6.2 now need to be reconsidered regarding the implication of “approving” a simplistic change to what may be an inappropriate standard. The Industry must identify such details as whether or not changes are made “annually” or “as needed”. What does it mean to “better suit the needs of an Interconnection”? Compliance entities need guidance about how to decide compliance. Do changes resulting from the ERO analysis occur on day-one that the change is made, or is there an implementation grace period - all this needs to be formally explained in the standard. Technically, the two BAL-002 requirements 4.2 and 6.2 that are in effect today, as well as the revised proposed actually introduce the potential to violate the Commission approved NERC standards development process as it allows the standard to be modified by a single entity outside the process. An alternative solution (one that meets the Commission mandate that allows the ERO to offer and equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be modified outside the standards development process. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested. Taken in isolation the concept of changing Regional Reliability Organization to Regional Entity would be reasonable. But does such a trivial change warrant expedited (i.e. Urgent Action) treatment by bypassing the FERC-approved Reliability Standards Development Process? Response: The Response Team agrees that the change is trivial, and as such, believes it should not require the several months of consensus building that is embodied within the RSDP.
Gregory Campoli	NYISO	2	Disapprove	Taken in isolation the concept of changing Regional Reliability Organization to Regional Entity would be reasonable. But does such a trivial change warrant expedited (i.e. Urgent Action) treatment by bypassing the FERC-approved Reliability Standards Development Process? Response: The Response Team agrees that the change is trivial, and as such, believes it should not require the several months of consensus building that is embodied within the RSDP.

Voter	Entity	Segment	P 321	Comments
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	The ERO change appears to be fine however this doesn't warrant a modification to the Standard. Response: The Response Team agrees that the change is trivial, and as such, believes it should not require the several months of consensus building that is embodied within the RSDP. Would it be possible to change RRO to RE throughout all these Tiger standards while we are in there? Response: The Response Team is undertaking this effort as appropriate with regard to the standards being modified as part of this project.
Donald S. Watkins	BPA	1	Disapprove	The ERO should not be determining the DCS period. There is no due process. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concern.
Terry L. Blackwell	Santee Cooper	1	Disapprove	The last sentence of R4.2 and R6.2 should be deleted from the standard. Any changes to the standards should follow the ANSIS approved standards process. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Disapprove	The process to modify these standards is not following the accept and approved process. The excuse that "FERC has expressed concern that industry and NERC have been less responsive than desired in providing a timely resolution to those directives." offers no urgent or compelling reason for this extraordinary step. It is suggested that NERC utilize the conventional standard modification process for the changes requested by FERC. Response: This project is using a process that has been approved by the Standards Committee. R4.2, 6.2. The last sentence "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the ERO." should be removed. Modification to the standards would require the standard approval process. To require that the ERO approve an analysis adds no improvement in reliability of the BES. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.

Voter	Entity	Segment	P 321	Comments
Ajay Garg	Hydro One Networks, Inc.	1	Approve	The proposed changes from P.321 is not enforceable or appropriate for a FERC approved requirement to be "adjustable" or waived. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concern.
Michael D. Penstone	Hydro One Networks, Inc.	3	Approve	
David H. Boguslawski	Northeast Utilities	1	Disapprove	The proposed changes from Paragraph 321 should include the striking of the sentence in R4.2 “This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating CommitteeERO.” It is not enforceable or appropriate for a FERC approved requirement to be “adjustable” or waived. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
Alan Gale	City of Tallahassee	5	Disapprove	The reference to the NERC OC pre-dates the mandatory enforcement era and any change in the time period should come through the NERC standards development process and applicable to all parties or for unique situations through the entity variance request. As written, the verbiage allows the ERO to unilaterally change the Disturbance and reserve recovery periods. Stike the last sentence, refering to modifications and I will be OK with it. Since no modifications have been identified to date, this should be acceptable to the ERO and to FERC. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	There has been no indications that the 15 minute disturbance recovery period has inpacted reliability. Giving the ERO the authority to change the disturbance recovery period would bypass the existing stakeholder process. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concern.
John Bos	Muscatine Power & Water	3	Disapprove	This would take away the stakeholders input Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concern.
Carolyn Ingersoll	Constellation Energy	3	Disapprove	To support of the standards development process, a better modification is to delete the phrase, “approved by the NERC Operating Committee” rather than

Voter	Entity	Segment	P 321	Comments
				change the reference from NERC OC to the ERO in R4.2 and 6.2. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	We can support the proposed changes from Paragraph 321 if the entire sentence in R 4.2 "This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee" were struck in its entirety. We do not believe it is enforceable or appropriate for a FERC-approved requirement to be "adjustable" or waived. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	While modifications to BAL-002 may address FERC directives, we do not believe simply replacing the NERC OC with the ERO is appropriate or represents the best solution. BAL-002 R4.2 and R6.2 that are in effect today and as proposed actually represent the potential to violate the Commission approved NERC standards development process as it allows the standard to be modified by a single entity outside the process. A superior alternative solution (which meets the Commission mandate that allows the ERO to offer an equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be modified outside the standards development process. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested. Modifying sub-requirements R4.2 and R6.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified its course of action would be.

Voter	Entity	Segment	P 321	Comments
				Response: The Response Team does not believe these changes are extensive enough to warrant a full restructuring of the requirements, measures, and VSLs.
Charles H Yeung	Southwest Power Pool	2	Disapprove	While modifications to BAL-002 may address previous FERC directives, we do not believe simply replacing the NERC OC with the ERO is appropriate or represents the best solution. BAL-002 R4.2 and R6.2 that are in effect today and as proposed actually represent the potential to violate the Commission-approved NERC Reliability Standards Development Process because those requirements allow the standard to be modified by a single entity outside the process. A superior alternative solution (i.e. a solution that allows the ERO to offer and equally effective, alternative solution) is to simply strike the last sentence of R4.2 and R6.2 so that it is clear that R4.2 and R6.2 will not be modified outside the standards development process. Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.

Summary Consideration for changes related to P330:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 330	Comments
Allen Mosher	APPA	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	

Voter	Entity	Segment	P 330	Comments
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Saurabh Saksena	National Grid	1	Abstain	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Michael T. Quinn	Oncor Electric Delivery	1	Abstain	
Jerome Murray	Oregon Public Utility Commission	9	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	

Voter	Entity	Segment	P 330	Comments
Daniel Baerman	San Diego G&E	5	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	

Voter	Entity	Segment	P 330	Comments
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Thomas E Washburn	FMPP	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Ajay Garg	Hydro One Networks, Inc.	1	Approve	
Michael D. Penstone	Hydro One Networks, Inc.	3	Approve	
Kim Warren	IESO	2	Approve	
Donald Gilbert	JEA	5	Approve	
Mace Hunter	Lakeland Electric	3	Approve	

Voter	Entity	Segment	P 330	Comments
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Dan R. Schoenecker	MRO	10	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power	3	Approve	

Voter	Entity	Segment	P 330	Comments
	Authority			
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	

Voter	Entity	Segment	P 330	Comments
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Francis J. Halpin	BPA	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	

Voter	Entity	Segment	P 330	Comments
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Scott Peterson	San Diego G&E	3	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	

Voter	Entity	Segment	P 330	Comments
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(a)In the definition of DSM, the parenthetical addes ambiguity. (b) Likewise, the implication that the DSM does not have to be controlled by an operator, means that DSM will not be comparabale, and will lead to less reliability. (c) In both definitions of Operating Reserve, "control capability" should be followed by "at a dispatch center or control room".
James Eckelkamp	Progress Energy	6	Disapprove	"Demand Side Management Resources" is used as an uppercase defined term in the definitions of Op. Reserve - Spinning and Op. Reserve - Supplemental, but it is not formally defined anywhere. Only "Demand Side Management" is newly defined in the proposed BAL-002-1. Did NERC intend to define ""Demand Side Management Resources"?
Wayne Lewis	Progress Energy Carolinas	5	Disapprove	
Terry L. Blackwell	Santee Cooper	1	Disapprove	Any changes to NERC definitions should follow the ANSI approved standards process.
Kevin Koloini	American Municipal Power - Ohio	4	Approve	Clarify Demand Side Management as Direct Control Load Management
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	Clarify in the definitions that intermittent generation resources are not considered suitable for operating or contingency reserves. Clarify in the definition that DSM Resources are loads under direct control of a NERC registered BA with a demonstrated capability to interrupt MW / MVAR reliably and within required times. While MidAmerican supports allowing DSM to compete with generation, the directives in paragraphs 330, 335, and 1232 are not low hanging fruit and need careful consideration. MidAmerican has concerns that including DSM as written could interfere with Operating Reserves and potentially reduce generation reserves further degrading system wide frequency response, opposite of a primary FERC concern. MidAmerican understands and applauds NERC efforts to be responsive but rushing to add DSM will likely incent the wrong type of DSM, most likely controllable loads

Voter	Entity	Segment	P 330	Comments
				that can be temporarily interrupted or reduced such as air conditioning, appliances, and the use of voltage reduction. These types of DSM do produce load reductions, but the demand returns with a vengeance in 15 - 30 minutes as controllers call for the reduced loads to compensate for the reduction by running harder and longer.MidAmerican does not believe that implementing this change will improve reliability as it will not advance the use of DSM since DSM is already used in nearly every major US market.
Danny McDaniel	Cleco Power LLC	1	Disapprove	Cleco is uncomfortable with the language: "Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service" because it does not specify the System Operator has control.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Lee Schuster	Florida Power Corporation	3	Disapprove	Demand Side Management Resources" is used as an uppercase defined term in the definitions of Op. Reserve - Spinning and Op. Reserve - Supplemental, but it is not formally defined anywhere. Only "Demand Side Management" is newly defined in the proposed BAL-002-1. Did NERC intend to define ""Demand Side Management Resources"?
Charles Locke	KCPL	3	Disapprove	Directives 330, 335, and 1232: In the definitions for "Operating Reserve - Spinning" and "Operating Reserve - Supplemental" the second bulleted item regarding Demand Side Management Resources should refer directly to "disturbance recovery period" instead of "time necessary to provide service". In addition, it is not clear that Demand Side Management actions can qualify as spinning as the load response or other actions is not automatically responsive to system changes. As an example, one of the actions could be the use of independent distributed generation resources to offset system load which is typically not synchronized to the grid.
Michael Gammon	KCPL	1	Disapprove	
Louise McCarren	WECC	10	Approve	I agree with removing the definition of Spinning Reserve from the revised version of BAL-002-1. However, the definition must remain in the NERC Glossary. The term exists in the existing approved regional reliability standard

Voter	Entity	Segment	P 330	Comments
				BAL-STD-002-0
Mel Jensen	APS	5	Disapprove	In the change of definition of Spinning Reserve, AZPS is uncomfortable with the language: "Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service" because it does not specify who has control. For Spinning Reserve, the control should be with the System Operator, as a quick response is necessary. For instance, an aggregator may offer demand management on a centralized basis using a control system under the control of the aggregator, but may require a phone call from the System Operator to activate. That may be too slow and not dependable enough for Spinning Reserve. AZPS suggests using Direct Control Load Management instead of DSM for Spinning Reserves.
Robert D Smith	Arizona Public Service Co.	1	Disapprove	
Rex A Roehl	Indeck Energy Services, Inc.	5	Disapprove	In the definitions of Operating Reserve - Spinning and Operating Reserve - Supplemental, DSM should be required to meet the "within the Disturbance Recovery Period following the contingency event" standard not some undefined one.
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate, and do not agree with the proposed definition for DSM. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome
Gregory Campoli	NYISO	2	Disapprove	Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to provide contingency reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the requirement itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. We do not agree with the proposed definition for DSM and, as a general matter, oppose inclusion or exclusion of specific types of resource

Voter	Entity	Segment	P 330	Comments
				or technology that may or may not be used to fulfill a requirement. We believe this results in a "HOW" to meet a requirement instead of "WHAT" to meet the requirements and, have, in the past opposed such specifications within the Standards. The ISO/RTOs currently allow DSM to compete with generation as a resource to supply contingency reserves. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. While these proposed changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply with the directive. We think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM. Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to provide contingency reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the requirement itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. We do not agree with the proposed definition for DSM and, as a general matter, oppose inclusion or exclusion of specific types of resource or technology that may or may not be used to fulfill a requirement. We believe this results in a "HOW" to meet a requirement instead of "WHAT" to meet the requirements and, have, in the past opposed such specifications within the Standards. The ISO/RTOs currently allow DSM to compete with generation as a resource to supply contingency reserves. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. While these proposed

Voter	Entity	Segment	P 330	Comments
				changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply with the directive. We think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM. Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC standards development process (i.e. NAESB participants).
Charles H Yeung	Southwest Power Pool	2	Disapprove	Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionarty list. The FERC mandate that DSM explicitly be allowed to provide contingency reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the requirement itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used.
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Disapprove	Need to develop what is 'adequate' with regard to DSM for spinning reserves. If we are to use loads for spin, it needs to respond to all frequency deviations the same as generators with load droop settings. It should not be allowed to only respond to
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	no spinning reserves in DSM. only direct control load management
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 330 and 335 - Demand Side Management: Though Duke Energy is a strong supporter of demand-side management including energy efficiency and other customer programs, we do not agree with the drafting team being selective in what clauses from FERC Order 693 are included in the draft Standard related to DSM, as the implications are significant and conflict with the FERC's expectations in its directives. Supporting the concerns of the industry, the FERC was clear in its expectation in paragraph 334 regarding the inclusion of DSM:"334. With regard to commenters' concern that DSM may not be technically possible, we first clarify that in order for DSM to participate, it must be technically capable of providing contingency reserve service. We

Voter	Entity	Segment	P 330	Comments
				expect that the ERO would determine what technical requirements DSM would need to meet to provide contingency reserves."As written, the draft BAL-002-1 leaves the technical requirements for inclusion of DSM unanswered, and by default, creates an obligation on every Balancing Authority and/or Transmission Service Provider to determine the technical requirements for qualification. Absent the inclusion of the technical requirements in the Standard, the directive for inclusion of DSM is not being met, and inconsistencies in the criteria developed independently by BAs and/or TSPs left on their own to sort through the qualification criteria will result in a different answer for each system, further driving the industry away from the FERCï¿½s other directive for the development of a continent-wide reserve policy. Paragraph 330 and 335 - DSM inclusion in Operating Reserve Definitions: The FERC in Paragraph 333 clarified that by requesting the inclusion of DSM in BAL-002, it was "simply attempting to make it inclusive of other technologies that may be able to provide contingency reserves, and are not directing the use of any particular type of resource." Though Duke Energy disagrees with continuing to add reserve resources traditionally considered "supplemental" or "non-spinning" to the "spinning" category without addressing the technical requirements as an industry (currently within the scope of the Balancing Authority Controls SDT under Project 2007-05), we believe that the current Operating Reserve definitions accommodate ANY controllable load capable of being removed from the system by the Balancing Authority within the Disturbance Recovery Period following the contingency event and meeting the technical requirements of the Balancing Authority for the provision of that service. The Operating Reserve definitions should not point to DSM as a third type of resource (as a separate bullet) as the applicable resources are either in the generation category or the load category. To the extent the standard moves forward with the inclusion of DSM, we would suggest that the definitions should continue to have a bullet applicable to generation and a bullet applicable to load, and that load could be modified to be inclusive of DSM, or more specifically the subset of DSM called Direct Control Load Management available to the system operator, and other load-related resources - for example:"Operating Reserve - Supplemental* Generation synchronized or capable of being synchronized to the system and fully available to the Balancing Authority to serve load within the Disturbance

Voter	Entity	Segment	P 330	Comments
				Recovery Period following the contingency event; or* Load, including Direct Control Load Management and other controllable load resources, fully removable from the system by the Balancing Authority within the Disturbance Recovery Period following the contingency event."
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	Revision introduces ambiguity with the establishment of a new Demand Side Management definition and use in the standard revising the makeup of Contingency Reserves to be generation, controllable resources, and DSM. "controllable resources" would otherwise seem to consist of generation and DSM. In proposed BAL-005-1, the phrase "controllable load resources" is used. What is intended? As written now, it appears load which may not be controllable will qualify under DSM for reserves.
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Disapprove	See BPA comments
Daniel Herring	Detroit Edison Co.	4	Disapprove	Specific technical requirements for inclusion of DSM need to be addressed in the standard.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	Spinning Reserve is used in other FERC approved standards. How does this deletion affect the WECC standards where it is used? How does this modification of Operating Reserve - Spinning and Operating Reserve - Supplemental affect other FERC approved standards? Since Operating Reserve - Spinning and Operating Reserve - Supplemental are part of Operating Reserve, and Operating Reserve is used many places in many FERC approved standards, how does this change affect those standards?
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Randall McCamish	City of Vero Beach	1	Disapprove	Spinning reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Spinning reserve is too important and under too much time pressure to not have direct System Operator control.
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	Spinning reserve shouldn't include any type of DSM, but rather only Direct Control Load Management; i.e., DSM under the direct control of the System Operator.

Voter	Entity	Segment	P 330	Comments
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	Supportive of DSM but as written it is unclear as what type programs can be used.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	The defintion of Spinning Reserve should be omitted from the standard and not deleted altogether. The revised definitions of OR-Spinning and OR-Supplemental include the phrase "within the Disturbance Recovery Period following the contingency event" four times, however alternate words are used for the new DSM piece. I believe a more-efficiant use of words could be used, such as moving this phrase to the top to cover all items listed and consider omitting "provide the service" because it is covered by the recovery period. Also, these definitions are included in other Standards such as RFC BAL-002-RFC-02 and those Standards need to be reviewed now and updated also.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	The inclusion of Demand Side Management (DSM) in requirement R1 and the proposed definition changes to DSM, Operating Reserve - Spinning and Operating Reserve Supplemental are beyond "low hanging fruit" that should be subject to this effort. While FE supports the inclusion of DSM as an alternative to a generation solution we believe this is a technical topic that requires careful consideration and vetting through a traditional standard development effort.DSM needs to be technically qualified and clarified as to what attributes of DSM represent a load impact perspective versus a resource “generation” perspective that can aid the BES in a manner similar to a traditional generation resource. These are highly technical topics which both the NERC OC and PC have opined upon and warrant further industry discussion outside of this particular standards effort to include the OC/PC positions as well as other industry SMEs. It is important that the technical attributes of the DSM definition be resolved before the DSM term is used in other areas of the standards.It is unclear why the SDT struck the word "load" in R1 as opposed to removing the entire phrase "controllable load resources". The resulting term "controllable resources" is left vague and open to interpretation and could include supply or demand side resources. Additionally, the R1 revision is inconsistent with the proposed definition of Regulating Reserve which the SDT added the term “controllable load resources” as well as the DSM term. Lastly, FE believes the potential for unintended consequences and impacts on other
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	

Voter	Entity	Segment	P 330	Comments
				standards and NAESB business practices require consideration.
James V. Petrella	Atlantic City Electric Co.	3	Disapprove	The term "within the Disturbance Recovery Period following the contingency event" should be used to describe Demand Side Management Resources.
Richard J Kafka	Potomac Electric Power Co.	1	Disapprove	
Brenda S. Anderson	BPA	6	Disapprove	The use of Demand Side Management for spinning reserves needs an additional requirement and a further description of "adequate" . Based on the use of Demand Side Management in the Spinning Reserve Requirement, Demand Side Management could act like Non-spin. "same response characteristics of the resources it is replacing". If load is going to be allowed to be used for spin, it should be responding to all frequency deviations, just like generators do with a droop setting. It shouldn't be allowed to only respond to large deviations or only internal contingencies. If allowed to only respond to contingencies, there will be a definite delay for contingencies external to their BA.
Donald S. Watkins	BPA	1	Disapprove	
Rebecca Berdahl	BPA	3	Disapprove	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Disapprove	
Dana Wheelock	Seattle City Light	3	Disapprove	
Dennis Sismaet	Seattle City Light	6	Disapprove	
Hao Li	Seattle City Light	4	Disapprove	
Pawel Krupa	Seattle City Light	1	Disapprove	
John Tolo	Tucson Electric Power Co.	1	Disapprove	uncomfortable with the language: "Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service" because it does not specify who has control.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	We do not agree with modifying the definition Operating Reserve - Spinningor Operating Reserve - Supplemental. What is different about DSM in new bulletthat the existing "load Fully removable..." bullet does not address. FERC hasmade clear recently through a March 18 order of their concern regardingdeclining frequency response in the Eastern Interconnection. Because OperatingReserve - Spinning has an implied obligation to include frequency responsivegeneration, we believe that the inclusion of DSM as written could further reducefrequency response. While some DSM may be frequency responsive, a significantportion may not be. At the very least, this demonstrates this is not low hangingfruit and should be referred to a drafting team. Additionally, we believe thepurpose of the BAL-002 standard is to set contingency reserve obligations and isnot an appropriate place to modify these definitions.Not sure why Demand Side Management is added to the list in BAL-002, R1when "Controllable load resources" already existed. The
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	

Voter	Entity	Segment	P 330	Comments
				difference is not clearand if it is based on the revised description of Demand Side Management will beproblematic because the new definition will not be universally accepted. Wedisagree with striking load. Controllable load resources may need to be struck inits entirety or retained in its entirety because it is not clear if these traditionalforms of load control would be lumped into the proposed definition of DSM.Controllable load resources traditionally would have included air conditioner, heatpump and/or water heater control that are directly controlled by the utility.However, the customer has to sign up for the program so one could argue that itmeets the proposed definition of DSM.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	We do not agree with the proposed definition for DSM and, as a general matter, oppose inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement. We believe this results in a “HOW” to meet a requirement instead of “WHAT” to meet the requirements and, have, in the past opposed such specifications within the Standards. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	We do not object to the content or intent of the directive, or to the intent of the proposed changes, however we believe the current wording is confusing. Specifically: a)It is not clear who “they” in the first sentence refers to. Grammatically it refers to end-use customers, LSEs, and their agents or representatives, but only end-use customers typically use electricity so we do not believe that was the intent. We suggest changing “the amount or timing of electricity they use” to “the amount or timing of electricity use”b)We believe it would read better and be easier to understand if the phrase “without violating Reliability Standards” was changed to “in accordance with Reliability Standards” and moved to after the word “undertaken”.c)The phrase “in order to provide the one or more services traditionally provided by generation resources” is vague. DSM addresses some of the same objectives as generation when viewed from a very high level, but does so in different ways. We recommend stating the objectives directly by replacing it with “to support voltage or frequency response or the balance of load and generation”.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	

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				If you disagree with this change, change “provide the one or more services” to “provide the services” d)We believe the last sentence is unnecessary because the same concept is conveyed in the definitions of spinning and supplemental reserves. If it is retained it should be reworded to improve its clarity. It starts with “In order to do so” but it is not clear exactly what that is referring to. It also says that the loads must have the same response characteristics of the resources it is replacing, but DSM is not defined as loads, but as activities. If it is retained we recommend replacing it with “to fall within the definition of DSM, an activity activities must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves.”e) Suggested re-wording of DSM: DSM - Programs operated in accordance with Reliability Standards to influence the amount or timing of electricity use in order to balance demand and resources or support frequency response. To fall within the definition of DSM, a program must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves.f)We recommend the second bullet of the definition of Spinning and Supplemental Reserves be changed to: Demand Side Management Resources with the capability to adequately respond within the time necessary to provide the service; orh)We recommend the third bullet of the definition of Spinning and Supplemental Reserves be deleted because anything covered by the third bullet would also be covered by the second.i)In BAL 002 R1 the term “controllable load resource” was changed to “controllable resource” We do not understand the intended meaning of controllable resources and it is not a defined term. We believe that a controllable resource would be either a form of generation or DSM which are already listed in R1; therefore we recommend that it be deleted.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	While we are supportive of allowing DSM to compete with generation as a resource to supply contingency reserves, we do not believe the directives from paragraph 330, 335, and 1232 regarding modifying BAL-002 represents low hanging fruit. While these proposed changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has on many occasions stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply

Voter	Entity	Segment	P 330	Comments
				with the directive. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. Unfortunately, we think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM. Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC standards development process (i.e. NAESB participants). We do not agree with modifying the definition Operating Reserve - Spinning or Operating Reserve - Supplemental. FERC has made clear recently through a March 18 order of their concern regarding declining frequency response in the Eastern Interconnection. Because Operating Reserve - Spinning has an implied obligation to include frequency responsive generation, we believe that the inclusion of DSM as written could further reduce frequency response. While some DSM may be frequency responsive, a significant portion may not be. At the very least, this demonstrates this is not low hanging fruit and should be referred to a drafting team. Additionally, we believe the purpose of the BAL-002 standard is to set contingency reserve obligations and is not an appropriate place to modify these definitions.BAL-002 R1 - We disagree with striking load. Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM. Controllable load resource may be something that is specifically included in DSM in that signing up could represent an activity “undertaken by end-use customers, Load -Serving Entities, or their agents or representatives to influence the amount or timing of electricity they use”. It is not clear though because of the ambiguity of the definition particularly since it is not clear what “Activities undertaken by end-use customers” includes.
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	Xcel Energy strongly supports FERC’s desire to clearly state that demand

Voter	Entity	Segment	P 330	Comments
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	resources can provide reserves on a comparable basis to generators as well as the position that demand-side resources can provide reserves to utilities. However, the term Demand-Side Management is not the best term to use to ensure this action and as proposed the changes to the definition and standard will cause confusion and make the standard less understood. Rather, Xcel Energy believes that the correct way to address FERC's concern would be to define the term Demand Response (as discussed in FERC Dockets RM05-5-017 and AD09-10) in the NERC Glossary and use this term in place of both interruptible load and Demand-Side Management in the proposed definitions of reserve types. The current definition of Demand-Side Management in the NERC glossary is the correct definition as used by the industry today. The term Demand-Side Management is much broader than just the programs that provide demand response to changing system conditions. The proposed definition is trying to change the meaning of the term to meet the desires of Commission. However, this change does not reflect what the term means to most in the electric industry. As an example, most entities (including state regulatory agencies Xcel Energy deals with) use the term Demand-Side Management to refer to programs such as replacing incandescent light bulbs with florescent light bulbs or installing more efficient appliances in place of older, less efficient appliances. Obviously, these programs cannot provide response as needed in a disturbance to restore balance between loads and resources. Changing the definition of the term to something that is not correct (and incorrect in its general use in the industry) will cause confusion and potentially errors in the application of the standards.For these reasons, Xcel Energy cannot support the proposed changes to the standard although we strongly support the intent on the proposed changes. Xcel Energy believes that while the desire of both NERC and FERC is moving in the right direction, in this case the means to get there will cause more confusion, which is unacceptable in the reliability standards. We believe that our proposal to define the term Demand Response in the NERC Glossary and incorporate its use in BAL-002 would provide all parties the desired result without creating confusion in the industry.

Summary Consideration for changes related to P335:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

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, Herb Schrayshuen, at 609-452-8060 or at Herb.Schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]

Voter	Entity	Segment	P 335	Comments
Allen Mosher	APPA	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	

[2] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	P 335	Comments
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Saurabh Saksena	National Grid	1	Abstain	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Michael T. Quinn	Oncor Electric Delivery	1	Abstain	
Jerome Murray	Oregon Public Utility Commission	9	Abstain	

Voter	Entity	Segment	P 335	Comments
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Daniel Baerman	San Diego G&E	5	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
John Yale	Chelan County Public Utility	5	Approve	

Voter	Entity	Segment	P 335	Comments
	District #1			
Linda R. Jacobson	City of Farmington	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Thomas E Washburn	FMPP	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Rex A Roehl	Indeck Energy Services, Inc.	5	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	

Voter	Entity	Segment	P 335	Comments
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Dan R. Schoenecker	MRO	10	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	

Voter	Entity	Segment	P 335	Comments
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	

Voter	Entity	Segment	P 335	Comments
Louise McCarren	WECC	10	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Donald S. Watkins	BPA	1	Disapprove	
Francis J. Halpin	BPA	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
George R. Bartlett	Entergy Corporation	1	Disapprove	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	

Voter	Entity	Segment	P 335	Comments
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Bruce Glorvigen	OTP Wholesale Marketing	6	Disapprove	
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Disapprove	
Scott Peterson	San Diego G&E	3	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	

Voter	Entity	Segment	P 335	Comments
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
John Tolo	Tucson Electric Power Co.	1	Disapprove	
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Alan Gale	City of Tallahassee	5	Disapprove	"The same response characteristics" is not the same as "similar technical requirements". How can a load that is moved to "off-peak" or simply reduced have the same performance characteristics of a generator synchronized and responding to frequency deviations? Or am I misunderstanding what is being asked for, hence it is not "clear and unambiguous"?
Terry L. Blackwell	Santee Cooper	1	Disapprove	Any changes to NERC definitions should follow the ANSI approved standards process
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	As written now, it appears load which may not be controllable will qualify under DSM for reserves, which is too uncertain as a reserve resource.
Carolyn Ingersoll	Constellation Energy	3	Approve	CECD suggests the following addition to the second sentence of the DSM definitions, which currently states “In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.” CECD would change the definition to state “In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the generation resource that would traditionally provide the function being met with DSM.”
Kevin Koloini	American Municipal Power - Ohio	4	Approve	Clarify Demand Side Management as Direct Control Load Management
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	Clarify in the definitions that intermittent generation resources are not considered suitable for operating or contingency reserves. Clarify in the definition that DSM Resources are loads under direct control of a NERC registered BA with a demonstrated capability to interrupt MW / MVAR reliably and within required times. DSM and generation are not comparable. Controllable loads that can be temporarily interrupted

Voter	Entity	Segment	P 335	Comments
				or reduced such as air conditioning, appliances, and the use of voltage reduction. These types of DSM do produce load reductions, but the demand returns with a vengeance in 15 - 30 minutes as controllers call for the reduced loads to compensate for the reduction by running harder and longer. Some loads such as irrigation loads can be reliably interrupted for indefinite periods and restored later after an emergency. Few customers would allow their loads to be interrupted without notifications as this usually results in lost product or workforce dismissals.
Danny McDaniel	Cleco Power LLC	1	Disapprove	Cleco is uncomfortable with the language: "Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service" because it does not specify the System Operator has control.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Charles H Yeung	Southwest Power Pool	2	Disapprove	Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM. Controllable load resource may be something that is specifically included in DSM in that signing up could represent an activity “undertaken by end-use customers, Load -Serving Entities, or their agents or representatives to influence the amount or timing of electricity they use”. It is not clear though because of the ambiguity of the definition particularly since it is not clear what “Activities undertaken by end-use customers” includes.Additionally, we recommend differentiating between Demand Side Management and Demand Response. NERC, via the Demand Response Data Task Force, provided solid differentiation between the two terms. See page 11 in the final report on the Demand Response Data Availability System (DADS):http://www.nerc.com/docs/pc/drdtf/DADS_Phase_I&II_Final_050510.pdfUnder NERC’s definition, DSM includes Energy Efficiency as well as Demand Response. Especially in the context of Contingency Reserves, as proposed here, dispatchable DR should be the only type of resource capable of participating; it is not likely anyone

Voter	Entity	Segment	P 335	Comments
				would recommend extending it to Energy Efficiency.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	Demand Side Management Resource should be defined since it has been included in the Standard.
Charles Locke	KCPL	3	Disapprove	Directives 330, 335, and 1232: In the definitions for "Operating Reserve - Spinning" and "Operating Reserve - Supplemental" the second bulleted item regarding Demand Side Management Resources should refer directly to "disturbance recovery period" instead of "time necessary to provide service". In addition, it is not clear that Demand Side Management actions can qualify as spinning as the load response or other actions is not automatically responsive to system changes. As an example, one of the actions could be the use of independent distributed generation resources to offset system load which is typically not synchronized to the grid.
Michael Gammon	KCPL	1	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	DSM is to unreliabile to be considerd a firm resource.
Lee Schuster	Florida Power Corporation	3	Disapprove	In the proposed new definition of DSM, the last sentence needs to be clarified: "In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing." First, this sentence should be revised to replace "loads" with "loads controllable by DSM". Second, which "response characteristics" are intended? Third, the parenthetical "but not necessarily mechanical or physical implementation" is not clear what is meant.
James Eckelkamp	Progress Energy	6	Disapprove	
Wayne Lewis	Progress Energy Carolinas	5	Disapprove	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	Inclusion of specific technologies in the requirements and definitions is inapropriate. The definition of DSM, or any definition for that matter, should not refer to "violatiing Reliability Standards." Any action taken by any entity must be done without violating reliability standards. This is a given.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate, and do not agree with the proposed definition for DSM. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	no spinning reserves in DSM. only direct control load management

Voter	Entity	Segment	P 335	Comments
Jeff Nelson	Springfield Utility Board	3	Disapprove	Please refer to SUB's comment form
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Please see our response to Paragraph 330.
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Disapprove	See BPA comments
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	See FE comments on paragraph item 330.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Timothy VanBlaricom	California ISO	2	Disapprove	Should delete the last sentence of the Definition of DSM. DSM will not have the 'same response characteristics' of a generator in many cases. DSM needs to meet the requirements specified in the definisitons of Operating Reserve - Spinning and Operating Reserve - Supplemental. DSM may not be replacing a generator, it may be in addition too.
Randall McCamish	City of Vero Beach	1	Disapprove	Spinning reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Spinning reserve is too important and under too much time pressure to not have direct System Operator control.
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	Spinning reserve shouldn't include any type of DSM, but rather only Direct Control Load Management; i.e., DSM under the direct control of the System Operator.
Donald Gilbert	JEA	5	Approve	The actual implementation of this Order to make sure DSM is technically comparable to traditional generators seems awkward. Not sure why we did not use FERC's words verbatim or at least just say must provide the same system electrical response as other comparable resources.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	The definition of DSM needs to be modified to replace word "load" with DSM Products. In the future, loads may not be the only DSM proudct capable of assuming this role.
Larry Akens	Tennessee Valley Authority	1	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	The existing definition of Contigency Reserve should be modified to state, "The portion of Operating Reserve used for responding to generation reporatble Disturbance".
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	The sentence "In order to do so, loads must have the same response characteristics(but

Voter	Entity	Segment	P 335	Comments
				not necessarily mechanical or physical implementation) of the resources it is replacing." is not acceptable since loads in DSM systems do not have the "same" dynamic response characteristics as generators. Comparable might be a better word than same.
Brenda S. Anderson	BPA	6	Disapprove	The use of Demand Side Management for spinning reserves needs an additional requirement and a further description of "adequate" . Based on the use of Demand Side Management in the Spinning Reserve Requirement, Demand Side Management could act like Non-spin. "same response characteristics of the resources it is replacing". If load is going to be allowed to be used for spin, it should be responding to all frequency deviations, just like generators do with a droop setting. It shouldn't be allowed to only respond to large deviations or only internal contingencies. If allowed to only respond to contingencies, there will be a definite delay for contingencies external to their BA.
Rebecca Berdahl	BPA	3	Disapprove	
Dana Wheelock	Seattle City Light	3	Disapprove	
Dennis Sismaet	Seattle City Light	6	Disapprove	
Hao Li	Seattle City Light	4	Disapprove	
Pawel Krupa	Seattle City Light	1	Disapprove	
Richard J. Mandes	Alabama Power Co.	3	Disapprove	Unclear how proposed words on definition accomplish FERC's desire to have them treated comparable. What does the last sentence mean..."response characteristics". All comments and changes ignore the fact that controllable loads are done so under the tariffs and contracts in place with the load not simply the fact that they are loads
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
Gregory Campoli	NYISO	2	Disapprove	We disagree with striking the word 'load' from BAL-001 R1. Controllable load resources may need to be struck in its entirety or retained in its entirety because it is not clear if these traditional forms of load control would be lumped into the proposed definition of DSM. Controllable load resources traditionally would have included air conditioner, heat pump and/or water heater control that are directly controlled by the utility. However, the customer has to sign up for the program so one could argue that it meets the proposed definition of DSM. Controllable load resource may be something that is specifically included in DSM in that signing up could represent an activity "undertaken by end-use customers, Load -Serving Entities, or their agents or representatives to influence the amount or timing of electricity they use". It is not clear though because of the ambiguity of the definition particularly since it is not clear what "Activities undertaken by end-use customers" includes.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	

Voter	Entity	Segment	P 335	Comments
Kim Warren	IESO	2	Disapprove	We do not agree with the change of definition of DSM especially the latter part that says: "...in order to provide the one or more services traditionally provided by generation resources. In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing." Further, the term Demand Side Manage Resource is used in the expanded definitions for Operating Reserve - Spinning and Operating Reserve - Supplemental. The word "Resource" should not be capitalized since it would imply a defined term.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	We do not agree with the proposed definition for DSM and, as a general matter, oppose inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement. We believe this results in a "HOW" to meet a requirement instead of "WHAT" to meet the requirements and, have, in the past opposed such specifications within the Standards. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	We do not object to the content or intent of the directive, or to the intent of the proposed changes, however we believe the current wording is confusing. Specifically: a)It is not clear who "they" in the first sentence refers to. Grammatically it refers to end-use customers, LSEs, and their agents or representatives, but only end-use customers typically use electricity so we do not believe that was the intent. We suggest changing "the amount or timing of electricity they use" to "the amount or timing of electricity use"b) We believe it would read better and be easier to understand if the phrase "without violating Reliability Standards" was changed to "in accordance with Reliability Standards" and moved to after the word "undertaken".c)The phrase "in order to provide the one or more services traditionally provided by generation resources" is vague. DSM addresses some of the same objectives as generation when viewed from a very high level, but does so in different ways. We recommend stating the objectives directly by replacing it with "to support voltage or frequency response or the balance of load and generation". If you disagree with this change, change "provide the one or more services" to "provide the services" d)We believe the last sentence is unnecessary because the same concept is conveyed in the definitions of spinning and supplemental reserves. If it is retained it should be reworded to improve its clarity. It
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	

Voter	Entity	Segment	P 335	Comments
				starts with “In order to do so” but it is not clear exactly what that is referring to. It also says that the loads must have the same response characteristics of the resources it is replacing, but DSM is not defined as loads, but as activities. If it is retained we recommend replacing it with “to fall within the definition of DSM, an activity activities must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves.”e) Suggested re-wording of DSM: DSM - Programs operated in accordance with Reliability Standards to influence the amount or timing of electricity use in order to balance demand and resources or support frequency response. To fall within the definition of DSM, a program must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves.f)We recommend the second bullet of the definition of Spinning and Supplemental Reserves be changed to: Demand Side Management Resources with the capability to adequately respond within the time necessary to provide the service; orh)We recommend the third bullet of the definition of Spinning and Supplemental Reserves be deleted because anything covered by the third bullet would also be covered by the second.i)In BAL 002 R1 the term “controllable load resource” was changed to “controllable resource” We do not understand the intended meaning of controllable resources and it is not a defined term. We believe that a controllable resource would be either a form of generation or DSM which are already listed in R1; therefore we recommend that it be deleted.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	We question that a load can have all the same response characteristics of a generator under all circumstances. The proposed Demand Side Management definition has embedded within it that end-use customers may not violate Reliability Standards. Which end-use customers and which Reliability Standards? Reliability Standards must apply to an entity before that entity can violate them. FERC has stated that for standards compliance an entity must be registered. Is NERC proposing to register end-use customers and modify standards to apply to end-use customers?
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Michael F Gildea	Dominion Resources Services	3	Approve	While we agree that the change in paragraph 335 meets FERC directives, we believe that the definition of the term Demand Side Management needs further clarity, in particular the sentence that reads “In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.” We suggest something similar to “A Demand-Side
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	

Voter	Entity	Segment	P 335	Comments
John K Loftis	Dominion Virginia Power	1	Approve	Management activity must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.”
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	While we are supportive of allowing DSM to compete with generation as a resource to supply contingency reserves, we do not believe the directives from paragraph 330, 335, and 1232 regarding modifying BAL-002 represents low hanging fruit. While these proposed changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has on many occasions stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply with the directive. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. Unfortunately, we think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM. Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC standards development process (i.e. NAESB participants).
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	Xcel Energy strongly supports FERC’s desire to clearly state that demand resources can provide reserves on a comparable basis to generators as well as the position that demand-side resources can provide reserves to utilities. However, the term Demand-Side Management is not the best term to use to ensure this action and as proposed the changes to the definition and standard will cause confusion and make the standard less understood. Rather, Xcel Energy believes that the correct way to address FERC’s concern would be to define the term Demand Response (as discussed in FERC Dockets RM05-5-017 and AD09-10) in the NERC Glossary and use this term in place of both interruptible load and Demand-Side Management in the proposed definitions of reserve types. The current definition of Demand-Side Management in the NERC glossary is the correct definition as used by the industry today. The term Demand-Side Management is much broader than just the programs that provide demand response to changing system conditions. The proposed definition is trying to change the meaning of the term to meet the desires of Commission. However, this change does not reflect what the term means to most in the electric industry. As an example, most entities (including state regulatory agencies Xcel Energy deals with) use the term Demand-Side Management to refer to programs such as replacing incandescent light bulbs with florescent light bulbs or installing more efficient appliances in place of older, less
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	

Voter	Entity	Segment	P 335	Comments
				efficient appliances. Obviously, these programs cannot provide response as needed in a disturbance to restore balance between loads and resources. Changing the definition of the term to something that is not correct (and incorrect in its general use in the industry) will cause confusion and potentially errors in the application of the standards.For these reasons, Xcel Energy cannot support the proposed changes to the standard although we strongly support the intent on the proposed changes. Xcel Energy believes that while the desire of both NERC and FERC is moving in the right direction, in this case the means to get there will cause more confusion, which is unacceptable in the reliability standards. We believe that our proposal to define the term Demand Response in the NERC Glossary and incorporate its use in BAL-002 would provide all parties the desired result without creating confusion in the industry.

Summary Consideration for changes related to P1232:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1232	Comments
Allen Mosher	APPA	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating	5	Abstain	

Voter	Entity	Segment	P 1232	Comments
	Station			
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Saurabh Saksena	National Grid	1	Abstain	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Michael T. Quinn	Oncor Electric Delivery	1	Abstain	
Jerome Murray	Oregon Public Utility	9	Abstain	

Voter	Entity	Segment	P 1232	Comments
	Commission			
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Daniel Baerman	San Diego G&E	5	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Liam Noailles	Xcel Energy, Inc.	5	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	

Voter	Entity	Segment	P 1232	Comments
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power	3	Approve	

Voter	Entity	Segment	P 1232	Comments
	Corporation			
Thomas E Washburn	FMPP	6	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Dan R. Schoenecker	MRO	10	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	

Voter	Entity	Segment	P 1232	Comments
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	

Voter	Entity	Segment	P 1232	Comments
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	

Voter	Entity	Segment	P 1232	Comments
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	
Louise McCarren	WECC	10	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Donald S. Watkins	BPA	1	Disapprove	
Timothy VanBlaricom	California ISO	2	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	

Voter	Entity	Segment	P 1232	Comments
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Mace Hunter	Lakeland Electric	3	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G	Omaha Public Power	1	Disapprove	

Voter	Entity	Segment	P 1232	Comments
Peterchuck	District			
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Disapprove	
Scott Peterson	San Diego G&E	3	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
John Tolo	Tucson Electric Power Co.	1	Disapprove	
Terry L. Blackwell	Santee Cooper	1	Disapprove	Any changes to NERC definitions should follow the ANSI approved standards process
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	As written now, it appears load which may not be controllable will qualify under DSM for reserves, which is too uncertain as a reserve resource.
Kevin Koloini	American Municipal Power - Ohio	4	Approve	Clarify Demand Side Management as Direct Control Load Management
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	Clarify in the definitions that intermittent generation resources are not considered suitable for operating or contingency reserves. Clarify in the definition that DSM Resources are loads under direct control of a NERC registered BA with a demonstrated

Voter	Entity	Segment	P 1232	Comments
				capability to interrupt MW / MVAR reliably and within required times.
Danny McDaniel	Cleco Power LLC	1	Disapprove	Cleco is uncomfortable with the language: "Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service" because it does not specify the System Operator has control.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Charles Locke	KCPL	3	Disapprove	Directives 330, 335, and 1232: In the definitions for "Operating Reserve - Spinning" and "Operating Reserve - Supplemental" the second bulleted item regarding Demand Side Management Resources should refer directly to "disturbance recovery period" instead of "time necessary to provide service". In addition, it is not clear that Demand Side Management actions can qualify as spinning as the load response or other actions is not automatically responsive to system changes. As an example, one of the actions could be the use of independent distributed generation resources to offset system load which is typically not synchronized to the grid.
Michael Gammon	KCPL	1	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	In R4.2, it should identify who (which group) at ERO; Enforcements, Stanadrds, Event Analysis?Also, what is the appeal process?
Richard J. Mandes	Alabama Power Co.	3	Disapprove	In the definition for DSM, we suggest the word "Load; be replaced with "DSM Products". In the future, loads many not be the only Demand side Product capable of assuming this role.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate, and do not agree with the proposed definition for DSM. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts

Voter	Entity	Segment	P 1232	Comments
				to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	It appears that the order directed the definition of DSM to include "any other entities". Why not include those words verbatim in the new definition. The applicability could include "Entities that provide DSM Resources"It's was a concern that while reviewing comments from others that Spinning Reserve and Operating Reserve-Spinning are sometimes used interchangeably by the industry.
Charles H Yeung	Southwest Power Pool	2	Disapprove	NERC definitions should not be written in terms of compliance requirement. Such requirements are defined by the standard itself. And such phrases as “of the resources it is replacing” is inappropriate and incorrect. One could ask if it were beteer to state “of the resources it is competing with”. And will it always compete with generation, may it not “replace” other DSM products? In short, the proposed defintion is not a good defintion.We suggest the definition be truncated at “....without violating other Reliability Standard Requirement”. Additionally, we recommend differentiating between Demand Side Management and Demand Response. NERC, via the Demand Response Data Task Force, provided solid differentiation between the two terms. See page 11 in the final report on the Demand Response Data Availability System (DADS):http://www.nerc.com/docs/pc/drdtf/DADS_Phase_I&II_Final_050510.pdfUnder NERC’s definition, DSM includes Energy Efficiency as well as Demand Response. Especially in the context of Contingency Reserves, as proposed here, dispatchable DR should be the only type of resource capable of participating; it is not likely anyone would recommend extending it to Energy Efficiency.
Michael F Gildea	Dominion Resources Services	3	Approve	Paragraph 1232 - in the definition for DSM, we suggest the word “Load; be replaced with “DSM Products”. In the future, loads many not be the only Demand side Product capable of assuming this role.
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	Paragraph 1232 - in the definition for DSM, we suggest the word “loads”; be replaced

Voter	Entity	Segment	P 1232	Comments
Stanley M Jaskot	Entergy Corporation	5	Approve	with “DSM Products”. The reason for the change is the fact that in the future loads many not be the only demand side product capable of assuming this role....”In order to do so, DSM Products must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.”
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 1232 - Modification of the DSM Definition: Duke Energy disagrees with the proposed modification to the definition of DSM as the FERC was specific in the change requested. We are not sure how to address the statement at the end of paragraph 1232 stating " without violating other Reliability Standard Requirement ". Customers cannot be held accountable to the Reliability Standard Requirements - if such language is to be included, perhaps it should be written to apply to Load Serving Entities or other Reliability Entities subject to NERC Reliability Standard compliance. As the technical requirements are addressed, we believe they will include the requirement that the resources be available to the system operator for implementation no different than other contingency reserve resources. Direct Control Load Management is DSM under the direct control of the system operator. To the extent such load is capable of being fully removed from the system within the Disturbance Recovery Period, we believe its use is already accommodated in the standard as indicated in our response above.In response to the FERC directive in 1232, Duke Energy would propose the following change to the DSM definition to read:" The term for all activities or programs undertaken by Load-Serving Entities and any other Reliability Entities to influence the amount or timing of electricity used without violation of applicable Reliability Standard Requirements."General Comment on Compliance Levels: The current compliance levels were removed by mistake and should be retained.
Kim Warren	IESO	2	Disapprove	Paragraph 1232 directs the ERO to expand the definition to add “any other entities that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement”. The proposed definition added the above mentioned wording which limit the scope of DSM within a specific type that is eligible for inclusion in the list that can used as a reserve. While this is the intent of the Paragraph 335 directive, such an intent should be met separately in a requirement, not in the definition. Including such wording in the definition exclude those demand that does not wish to be included in, or qualify for, providing services traditionally provided by generation resources such as not having the same response characteristics.We suggest the definition be truncated at “....without violating other Reliability Standard Requirement”. The part that says “...in order to provide the one or

Voter	Entity	Segment	P 1232	Comments
				more.....resources it is replacing." be removed, and whose intent to allow the use of DSM as a resource for contingency reserves, and that it be treated on a comparable basis and must meet similar technical requirements as other resources providing this service be covered by appropriate requirements.
Jeff Nelson	Springfield Utility Board	3	Disapprove	Please refer to SUB's comment form
Daniel Herring	Detroit Edison Co.	4	Disapprove	Proposed modification of DSM does not meet the FERC request and unregistered "other entities" or end use customers have no responsibility to adhere to the NERC Reliability Standards so the inclusion of this language is meaningless.
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Disapprove	See BPA comments
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	See FE comments on paragraph item 330.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	See FE comments on paragraph item 330.
Rex A Roehl	Indeck Energy Services, Inc.	5	Disapprove	The addition of "any other entities" didn't happen in the DSM definition.
Donald Gilbert	JEA	5	Disapprove	The circular reference for a DSM resource to be compliant with Reliability Standards seems problematic and legally challenging. Why not just require end users and aggregators to be subject to NERC Registration and compliance and assign specific Standards for their compliance. I do not want as a subscriber to a DSM sevice to be held accountable for the behavior of the service provider in regards to this generic prohibition on "violating Reliability Standards".
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	In the definition for DSM, we suggest the word "Load" be replaced with "DSM Products". In the future, loads may not be the only Demand side Product capable of assuming this role.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	The definition of DSM needs to be modified to replace word "load" with DSM Products. In the future, loads may not be the only DSM proudct capable of assuming this role.
Larry Akens	Tennessee Valley Authority	1	Disapprove	The definition of DSM needs to be modified to replace word "load" with DSM Products. In the future, loads may not be the only DSM proudct capable of assuming this role.

Voter	Entity	Segment	P 1232	Comments
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	The definition of DSM, or any definition for that matter, should not refer to "violatiing Reliability Standards." Any action taken by any entity must be done without violating reliability standards. This is a given.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Gregory Campoli	NYISO	2	Disapprove	The proposed definition of DSM is inappropriate as it proposes to link the definition to a given purpose (i.e. providing one or more services...). Paragraph 1232 directed the ERO to expand the original DSM definition adding the phrase: “any other entities that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement”. The SAR-proposed definition - in addition to including the Order 693 wording - proposes to limit the scope of DSM within a specific type that is eligible for inclusion in being used as a reserve. While this is the intent of the Paragraph 335 directive, such an intent should be met separately in a requirement, not in the definition. Including such wording in the DSM definition would effectively exclude (as DSM) those demand side management resources that do not wish to be included in, or qualify for, providing services traditionally provided by generation resources such as not having the same response characteristics. Although FERC suggested the wording used in this proposal, the requestor is reminded that FERC has repeated stated that equally effective alternatives are appropriate. The words need to be considered and vetted in light of all DSM initiatives. NERC has several DSM activities now in process. The reason for those activities is specifically because DSM (as an evolving technology) is not a well-defined universally accepted term. NERC definitions should not be written in terms of compliance requirement. Such requirements are defined by the standard itself. And such phrase as “of the resources it is replacing” is inappropriate and incorrect. One could ask if it were better to state “of the resources it is competing with”. And will it always compete with generation, may it not “replace” other DSM products? In short, the proposed definition is not a good definition.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	The proposed definition of DSM is inappropriate as it proposes to link the definition to a given purpose (i.e. providing one or more services...). Paragraph 1232 directed the ERO to expand the original DSM definition adding the phrase: “any other entities that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement”. The SAR-proposed definition - in addition to including the Order 693 wording - proposes to limit the scope of DSM within a specific type that is eligible for inclusion in being used as a reserve. While this is

Voter	Entity	Segment	P 1232	Comments
				the intent of the Paragraph 335 directive, such an intent should be met separately in a requirement, not in the definition. Including such wording in the DSM definition would effectively exclude (as DSM) those demand side management resources that do not wish to be included in, or qualify for, providing services traditionally provided by generation resources such as not having the same response characteristics. Although FERC suggested the wording used in this proposal, the requestor is reminded that FERC has repeated stated that equally effective alternatives are appropriate. The words need to be considered and vetted in light of all DSM initiatives. NERC has several DSM activities now in process. The reason for those activities is specifically because DSM (as an evolving technology) is not a well-defined universally accepted term. NERC definitions should not be written in terms of compliance requirement. Such requirements are defined by the standard itself. And such phrase as "of the resources it is replacing" is inappropriate and incorrect. One could ask if it were better to state "of the resources it is competing with". And will it always compete with generation, may it not "replace" other DSM products? In short, the proposed definition is not a good definition.
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	The sentence "In order to do so, loads must have the same response characteristics(but not necessarily mechanical or physical implementation) of the resources it is replacing." is not acceptable since loads in DSM systems do not have the "same" dynamic response characteristics as generators. Comparable might be a better word than same.
Brenda S. Anderson	BPA	6	Disapprove	The use of Demand Side Management for spinning reserves needs an additional requirement and a further description of "adequate" . Based on the use of Demand Side Management in the Spinning Reserve Requirement, Demand Side Management could act like Non-spin. "same response characteristics of the resources it is replacing". If load is going to be allowed to be used for spin, it should be responding to all frequency deviations, just like generators do with a droop setting. It shouldn't be allowed to only respond to large deviations or only internal contingencies. If allowed to only respond to contingencies, there will be a definite delay for contingencies external to their BA.
Francis J. Halpin	BPA	5	Disapprove	
Rebecca Berdahl	BPA	3	Disapprove	
Dana Wheelock	Seattle City Light	3	Disapprove	
Dennis Sismaet	Seattle City Light	6	Disapprove	
Hao Li	Seattle City Light	4	Disapprove	
Pawel Krupa	Seattle City Light	1	Disapprove	
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	We do not agree with the proposed definition for DSM and, as a general matter, oppose inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement. We believe this results in a "HOW" to meet a requirement instead of

Voter	Entity	Segment	P 1232	Comments
				"WHAT" to meet the requirements and, have, in the past opposed such specifications within the Standards. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	We do not object to the content or intent of the directive, or to the intent of the proposed changes, however we believe the current wording is confusing. Specifically: a)It is not clear who "they" in the first sentence refers to. Grammatically it refers to end-use customers, LSEs, and their agents or representatives, but only end-use customers typically use electricity so we do not believe that was the intent. We suggest changing "the amount or timing of electricity they use" to "the amount or timing of electricity use"b) We believe it would read better and be easier to understand if the phrase "without violating Reliability Standards" was changed to "in accordance with Reliability Standards" and moved to after the word "undertaken".c)The phrase "in order to provide the one or more services traditionally provided by generation resources" is vague. DSM addresses some of the same objectives as generation when viewed from a very high level, but does so in different ways. We recommend stating the objectives directly by replacing it with "to support voltage or frequency response or the balance of load and generation". If you disagree with this change, change "provide the one or more services" to "provide the services" d)We believe the last sentence is unnecessary because the same concept is conveyed in the definitions of spinning and supplemental reserves. If it is retained it should be reworded to improve its clarity. It starts with "In order to do so" but it is not clear exactly what that is referring to. It also says that the loads must have the same response characteristics of the resources it is replacing, but DSM is not defined as loads, but as activities. If it is retained we recommend replacing it with "to fall within the definition of DSM, an activity activities must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves."e) Suggested re-wording of DSM: DSM - Programs operated in accordance with Reliability Standards to influence the amount or timing of electricity use in order to balance demand and resources or support frequency response. To fall within the definition of DSM, a program must meet the Reliability Standards criteria established for its function, e.g. DSM used as Spinning Reserves must meet all criteria for Spinning Reserves.f)We recommend the second bullet of the definition of Spinning and Supplemental Reserves be changed to: Demand Side
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	

Voter	Entity	Segment	P 1232	Comments
				Management Resources with the capability to adequately respond within the time necessary to provide the service; orh)We recommend the third bullet of the definition of Spinning and Supplemental Reserves be deleted because anything covered by the third bullet would also be covered by the second.i)In BAL 002 R1 the term "controllable load resource" was changed to "controllable resource" We do not understand the intended meaning of controllable resources and it is not a defined term. We believe that a controllable resource would be either a form of generation or DSM which are already listed in R1; therefore we recommend that it be deleted.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	We question that a load can have all the same response characteristics of a generator under all circumstances. The proposed Demand Side Management definition has embedded within it that end-use customers may not violate Reliability Standards. Which end-use customers and which Reliability Standards? Reliability Standards must apply to an entity before that entity can violate them. FERC has stated that for standards compliance an entity must be registered. Is NERC proposing to register end-use customers and modify standards to apply to end-use customers?
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	While we are supportive of allowing DSM to compete with generation as a resource to supply contingency reserves, we do not believe the directives from paragraph 330, 335, and 1232 regarding modifying BAL-002 represents low hanging fruit. While these proposed changes may meet the letter of the directives, we do not believe they represent good solutions and remind the drafting team that FERC has on many occasions stated that equally effective alternatives that meet the reliability objective are acceptable ways to comply with the directive. Furthermore, we do not believe that implementing this change will advance the use of DSM in any way within the industry since its use is already required in virtually every major energy market in the U.S. through their FERC approved tariffs. Unfortunately, we think these changes, if not crafted carefully, could potentially result in a reduction in reliability or at a minimum cause additional confusion regarding the use of DSM. Furthermore, we believe the definition of DSM could benefit from the input of experts from outside the typical NERC standards development process (i.e. NAESB participants).
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	Xcel Energy strongly supports FERC's desire to clearly state that demand resources can provide reserves on a comparable basis to generators as well as the position that demand-side resources can provide reserves to utilities. However, the term Demand-Side Management is not the best term to use to ensure this action and as proposed the
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	

Voter	Entity	Segment	P 1232	Comments
				changes to the definition and standard will cause confusion and make the standard less understood. Rather, Xcel Energy believes that the correct way to address FERC's concern would be to define the term Demand Response (as discussed in FERC Dockets RM05-5-017 and AD09-10) in the NERC Glossary and use this term in place of both interruptible load and Demand-Side Management in the proposed definitions of reserve types. The current definition of Demand-Side Management in the NERC glossary is the correct definition as used by the industry today. The term Demand-Side Management is much broader than just the programs that provide demand response to changing system conditions. The proposed definition is trying to change the meaning of the term to meet the desires of Commission. However, this change does not reflect what the term means to most in the electric industry. As an example, most entities (including state regulatory agencies Xcel Energy deals with) use the term Demand-Side Management to refer to programs such as replacing incandescent light bulbs with florescent light bulb or installing more efficient appliances in place of older, less efficient appliances. Obviously, these programs cannot provide response as needed in a disturbance to restore balance between loads and resources. Changing the definition to something that is not the intent of the term (and its general use in the industry) will cause confusion and potentially errors in the application of the standards.For these reasons, Xcel Energy cannot support the proposed changes to the standard although we strongly support the intent on the proposed changes. Xcel Energy believes that while the desire of both NERC and FERC is moving in the right direction, in this case the means to get there will cause more confusion, which is unacceptable in the reliability standards. We believe that our proposal to define the term Demand Response in the NERC Glossary and incorporate its use in BAL-002 would provide all parties the desired result without creating confusion in the industry.

Summary Consideration for changes related to P404:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 404	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	APPA	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Dennis Minton	Florida Keys Electric	1	Abstain	

Voter	Entity	Segment	P 404	Comments
	Cooperative Assoc.			
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Saurabh Saksena	National Grid	1	Abstain	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Brian Evans-	Utility Services, Inc.	8	Abstain	

Voter	Entity	Segment	P 404	Comments
Mongeon				
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	BPA	6	Approve	
Donald S. Watkins	BPA	1	Approve	
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Danny McDaniel	Cleco Power LLC	1	Approve	
Bryan Y Harper	Cleco Utility Group	3	Approve	

Voter	Entity	Segment	P 404	Comments
Paul Morland	Colorado Springs Utilities	1	Approve	
Brenda Powell	Constellation	6	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
Dan Roethemeyer	Dynegy Inc.	5	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	

Voter	Entity	Segment	P 404	Comments
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Donald Gilbert	JEA	5	Approve	
Charles Locke	KCPL	3	Approve	
Michael Gammon	KCPL	1	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Brad Jones	Luminant Energy	6	Approve	
Mike Laney	Luminant Generation Co. LLC	5	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy	1	Approve	

Voter	Entity	Segment	P 404	Comments
	Co.			
Dan R. Schoenecker	MRO	10	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	

Voter	Entity	Segment	P 404	Comments
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	

Voter	Entity	Segment	P 404	Comments
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	

Voter	Entity	Segment	P 404	Comments
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	
Louise McCarren	WECC	10	Approve	
David F. Lemmons	Xcel Energy, Inc.	6	Approve	
Gregory L Pieper	Xcel Energy, Inc.	1	Approve	
Liam Noailles	Xcel Energy, Inc.	5	Approve	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	

Voter	Entity	Segment	P 404	Comments
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Mace Hunter	Lakeland Electric	3	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	

Voter	Entity	Segment	P 404	Comments
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(a) The new definition introduces an acronym (ARC) that is already used by FERC for Aggregate Retail Customer(b) The proposed ARC definition should modify "Balancing Authority's interchange..." to "Balancing Authority Area's interchange ...", since BA does not have a schedulem rather a BAA does (e.g. one BA may operate multiple BAA). (c) In the Regulating Reserve definition add "to generation resources" between comparable and response in the last phrase. (d)In R7, the team uses ARC but refers to generation.
Mark Peters	Ameren Services	3	Disapprove	
Greg C Parent	Manitoba Hydro	3	Approve	404 - Manitoba Hydro only uses on line (spinning) generation for regulating reserve. Changing “Automatic Generation Control” to “Automatic Resource Control” most likely encompasses a variety of regulating reserves used by all BA’s in NERC. Regarding balancing interchange/ACE, only on line generation will response to AGC. Other resources such as load curtailments are operator instigated and assist AGC, but does not directly respond to AGC. My only point is that the changing of an age old acronym AGC to ARC.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	5a) We agree with the intent, but disagree with the wording. We believe that “controllable load resources” are included within DSM and thus the inclusion of both is unnecessary and confusing. If the language is retained we suggest that it be made consistent with BAL 002 (controllable load resources vs. controllable resources).We recommend:5b) Under Compliance 1.1 it refers to “their” Regional Entity. However, 1.1.1. refers to “the” Regional Entity. We recommend consistency. Also as a general statement the use of the term Regional Entity (RE) vs. Regional Reliability Organization (RRO) should be reviewed in all of these documents to ensure consistency.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	
Richard J. Mandes	Alabama Power Co.	3	Disapprove	AGC is an industry accepted term that has a specific meaning related tosoftware and telemetry. Controlling load would/does require different softwareand telemetry.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	

Voter	Entity	Segment	P 404	Comments
Gwen S Frazier	Gulf Power Co.	3	Disapprove	Reference to a new term Automatic Demand Control may beeasier. The idea of controlling load for regulation would be a stretch. Doing it forcontingencies or capacity makes some sense but regulation does not. One canvary the output of a generator to obtain moment-to-moment regulation butloads would not be expected to have that characteristic due to the real-timeuncertainty/variability forced on the customer. A load is normally on or off unlikea generator.
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	AGC is an industry accepted term that has a specific meaning related to software and telemetry. Controlling load would/does require different software and telemetry. Reference to a new term Automatic Demand Control may be easier. The idea of controlling load for regulation would be a stretch. Doing it for contingencies or capacity makes some sense but regulation does not. One can vary the output of a generator to obtain moment-to-moment regulation but loads would not be expected to have that characteristic due to the real-time uncertainty/variability forced on the customer. A load is normally on or off unlike a generator.
Terry L. Blackwell	Santee Cooper	1	Disapprove	Any changes to NERC definitions should follow the ANSI approved standards process.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	As a general matter, we oppose inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement. We believe this results in a “HOW” to meet a requirement instead of “WHAT” to meet the requirements and, have, in the past opposed such specifications within the Standards. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	As written, the change from AGC to ARC makes the BA responsible in standards compliance for DSM actions of an LSE or end-use customer but does not give the BA any authority in the DSM actions of the LSE or end-use customer. What is the effect of the change from AGC to ARC in all the other FERC approved standards?
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."

Voter	Entity	Segment	P 404	Comments
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	In R7 & R14, generation should be replaced by "resource"Deamand Side Management Resource should be defined and replace DSM in the revised defintion of Regulating Reserve; DSM is an activity and program, not a MW resource.Also, we believe that ARC is an accronym in MISO for the Aggregated Retail Customer which is somewhat related to DSM, which may cause confusion.
Timothy VanBlaricom	California ISO	2	Disapprove	In the definition of Regulating Reserve we feel that 'comparable response characteristics' is not appropriate and vague. All the resources just need to be responsive to ARC and sufficient to provide normal regulating margin. There is no response characteristic required
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. NERC should find an alternate method to address the Commissions' concern rather than simply "renaming" a widely, industry accepted and understood definition and concept such as "AGC."
Daniel Prowse	Manitoba Hydro	6	Approve	Manitoba Hydro only uses on line (spinning) generation for regulating reserve. Changing "Automatic Generation Control" to "Automatic Resource Control" most likely encompasses a variety of regulating reserves used by all BA's in NERC. Regarding balancing interchange/ACE, only on line generation will response to AGC. Other resources such as load curtailments are operator instigated and assist AGC, but does not directly respond to AGC. My only point is that the changing of an age old acronym AGC to ARC.
Michelle Rheault	Manitoba Hydro	1	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	no regulation reserves in DSM. only direct control load management
Charles H Yeung	Southwest Power Pool	2	Disapprove	o The proposed changes exceed the Commission directive. The directive is only required to the title not throughout the entire document, it was not to change the

Voter	Entity	Segment	P 404	Comments
				defintion of AGC. o The FERC mandate is that DSM explicitly be allowed to provide regulating reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the definiton itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	o The proposed changes exceed the Commission directive. The directive is to change the title not throughout the entire document, it was not to change the definition of AGC. o The requestor would have been more correct if the proposal were to change the title from Automatic Generation Control to something as simple as "Area Control Error" or "Balancing Control". o As proposed, any automatic process used in balancing would come under this umbrella. For example, if a BA used UFLS resources to help maintain its ACE, then by this definition UFLS would be AGC. o The term AGC should be considered for removal. There is no one control system - indeed many if not all control systems have their unique characteristics. What the standard mandates is the calculation and use of Area Control Error (ACE). o AGC is a generic industry term for a control process and not specific to any one resource. It is a term used by vendors and academics and Control Theory books. Thus AGC programs do have meaning to those outside our standard process, and those who service our control programs. o Regarding the proposed conforming changes to the first sentence of the definition of regulating Reserve, we question the need for the second sentence in the definition. o The FERC mandate is that DSM explicitly be allowed to provide regulating reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the definition itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	Object to inclusion of load (DSM) which is not controllable as a component of regulating reserves.
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 404 and 420 - Renaming the title of BAL-005: The FERC directive was to change the title. Duke Energy agrees with renaming BAL-005, however we question the value of changing the term " AGC " which is so widely known in the industry, and referenced in systems, applications and documentation. Are we sure we want to

Voter	Entity	Segment	P 404	Comments
				confuse everyone simply for the sake of nomenclature? Though the change from AGC to ARC is purely semantic, AGC is a less likely term to be used for other processes/procedures, whereas " ARC " is a convenient acronym for any automated ramp, automated reserve, automated resource, available ramp, available regulation, or available reserve criteria, calculator, coordination, capacity, or curtailment developed. " ARC " is easy to remember so it is used in many ways. For example, in 2006 the Midwest ISO filed its Adequate Ramp Capability or " ARC " procedure with the FERC to enhance its ability to manage potential real-time energy shortage conditions within its market. We also note that FERC recently issued Orders using the term Aggregators of Retail Choice creating another use of the term ARC.Duke Energy would support changing the title of the standard as proposed but not pushing a new and potentially confusing acronym out to the industry. We would support adding the following to the definition of AGC:" Equipment that automatically adjusts generation and/or load resources in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction."
Jeff Nelson	Springfield Utility Board	3	Disapprove	Please refer to SUB's comment form
Randall McCamish	City of Vero Beach	1	Disapprove	Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative.
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative in the definition of Regulating Reserve.
Walt Gill	Lake Worth Utilities	1	Disapprove	Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative.
Larry E Watt	Lakeland Electric	1	Disapprove	
Terri Pyle	Oklahoma Municipal	4	Disapprove	Regulation reserve should not include any type of DSM. Should be Direct Control Load

Voter	Entity	Segment	P 404	Comments
	Power Authority			Management under the direct control of the System Operator.
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	See our comment above re. inclusion of technologies.NERC should find an alternative method to address the directive rather than simply renaming a widely, industry accepted and understood definition and concept as "AGC."
Rex A Roehl	Indeck Energy Services, Inc.	5	Disapprove	The definition of ARC deletes "from a central location" from the AGC definition. As the definition of Regulating Reserve indicates the Reserve must be "responsive", that response must be to BA/TOP control signals as generators do. FERC's directive requires "qualified DSM and direct control load" be included in ARC. Neither definition qualifies those resources as FERC did. Are any of these Resources likely to be Registered Entities, subject to these standards? Suggestion: Regulating Reserve: Regulating Reserve may be comprised of generation, directly controllable load resources, technically qualified Demand Side Management (DSM), or other resources that are controllable from a central location and have comparable response characteristics.
Kevin Koloini	American Municipal Power - Ohio	4	Approve	The GOP and LSE requirements are not defined in the Compliance Monitoring or VSL sections.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	The proposed changes actually exceed the Commission directive from paragraph 404. The change is only required to the title not throughout the entire document.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	The proposed changes go beyond the FERC requested title change of the standard. The change from Automatic Generation Control (AGC) to Automatic Resource Control (ARC) while seemingly trivial may have unintended consequences and requires further consideration. It is unclear what would be considered an automatic resource (load) control used in controlling ACE. While there are automatic load shedding schemes for frequency and voltage or potentially load shed through a SPS we are not aware of system designs automatically managing load to control ACE. Load interrupted for demand side management is typically operator initiated.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Gregory Campoli	NYISO	2	Disapprove	The proposed definition of DSM is inappropriate as it proposes to link the definition to a given purpose (i.e. providing one or more services...). Paragraph 1232 directed the ERO to expand the original DSM definition adding the phrase: "any other entities that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement". The SAR-proposed definition - in addition to including the Order 693 wording - proposes to limit the scope

Voter	Entity	Segment	P 404	Comments
				of DSM within a specific type that is eligible for inclusion in being used as a reserve. While this is the intent of the Paragraph 335 directive, such an intent should be met separately in a requirement, not in the definition. Including such wording in the DSM definition would effectively exclude (as DSM) those demand side management resources that do not wish to be included in, or qualify for, providing services traditionally provided by generation resources such as not having the same response characteristics. Although FERC suggested the wording used in this proposal, the requestor is reminded that FERC has repeated stated that equally effective alternatives are appropriate. The words need to be considered and vetted in light of all DSM initiatives. NERC has several DSM activities now in process. The reason for those activities is specifically because DSM (as an evolving technology) is not a well-defined universally accepted term. NERC definitions should not be written in terms of compliance requirement. Such requirements are defined by the standard itself. And such phrase as “of the resources it is replacing” is inappropriate and incorrect. One could ask if it were better to state “of the resources it is competing with”. And will it always compete with generation, may it not “replace” other DSM products? In short, the proposed definition is not a good definition.NERC should find an alternate method to address the Commissions’ concern rather than simply “renaming” a widely, industry accepted and understood definition and concept such as “AGC.”
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Disapprove	The term "AGC" is used throught industry and the Reliability Standards. Unless the other standards are modified under this project, it is suggested that it would be more expedient to modify the term AGC to allow for oher resources to be included and not worry about the Generation part of the term. This will avoid confusion with other standards, criteria, and procedures. In addition the definition cannot include all resources, just those that are controllable. The Definition should be rewritten as "Automatic Generation Control (AGC): Automatic adjustment of generation and other controllable resources in a Balancing Authority Area to maintain the Balancing Authority’s interchange schedule plus Frequency Bias. ARC may also accommodate automatic inadvertent payback and time error correction."Examples of other Standards that use the term AGC include BAL 003, 004, 005, 006, and BAL-Std-002.
Kim Warren	IESO	2	Approve	We agree with the proposed definition of ARC and the proposed conforming changes to the first sentence of the definition of Regulating Reserve. However, we question the need for the second sentence in the latter definition, although we do not find it

Voter	Entity	Segment	P 404	Comments
				unacceptable.

Voter	Entity	Segment	P 404 VSL changes	Comments
Raj Rana	AEP	3	In Favor	
Edward P. Cox	AEP Marketing	6	In Favor	
Brock Ondayko	AEP Service Corp.	5	In Favor	
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	In Favor	
Allen Mosher	APPA	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Donald S. Watkins	BPA	1	In Favor	
Francis J. Halpin	BPA	5	In Favor	
Rebecca Berdahl	BPA	3	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R.	City of Farmington	3	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
Jacobson				
Gregg R Griffin	City of Green Cove Springs	3	In Favor	
Alan Gale	City of Tallahassee	5	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Brenda Powell	Constellation	6	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	In Favor	
David A. Lapinski	Consumers Energy	3	In Favor	
David Frank Ronk	Consumers Energy	4	In Favor	
James B Lewis	Consumers Energy	5	In Favor	
Russell A Noble	Cowlitz County PUD	3	In Favor	
Daniel Herring	Detroit Edison Co.	4	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	In Favor	
George R. Bartlett	Entergy Corporation	1	In Favor	
Stanley M Jaskot	Entergy Corporation	5	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Greg Froehling	Green Country Energy	5	In Favor	
Kim Warren	IESO	2	In Favor	
Rex A Roehl	Indeck Energy Services, Inc.	5	In Favor	
Donald Gilbert	JEA	5	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
Charles Locke	KCPL	3	In Favor	
Michael Gammon	KCPL	1	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Daniel Duff	Liberty Electric Power LLC	5	In Favor	
Doug Bantam	LES	1	In Favor	
Dennis Florom	LES	5	In Favor	
Eric Ruskamp	LES	6	In Favor	
Brad Jones	Luminant Energy	6	In Favor	
Mike Laney	Luminant Generation Co. LLC	5	In Favor	
Daniel Prowse	Manitoba Hydro	6	In Favor	
Steven M. Jackson	MEAG	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	
Terry Harbour	MidAmerican Energy Co.	1	In Favor	
John Bos	Muscatine Power & Water	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
Bradley Tollerson	OTP Wholesale Marketing	3	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Terry L Baker	Platte River Power Authority	3	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
John C. Collins	Platte River Power Authority	1	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Laurie Williams	Public Service Co. of New Mexico	1	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
John T. Underhill	Salt River Project	3	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Terry L. Blackwell	Santee Cooper	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Dennis Sismaet	Seattle City Light	6	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	In Favor	
Bethany Wright	SMUD	5	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Mike Ramirez	SMUD	4	In Favor	
Tim Kelley	SMUD	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
Steve McElhaney	South Mississippi Electric Power Association	4	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
Jerry W Johnson	South Mississippi Electric Power Association	5	In Favor	
Richard McLeon	South Texas Electric Cooperative	1	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
George T. Ballew	Tennessee Valley Authority	5	In Favor	
Larry Akens	Tennessee Valley Authority	1	In Favor	
Marjorie Parsons	Tennessee Valley Authority	6	In Favor	
Jonathan Appelbaum	United Illuminating Co.	1	In Favor	
Brandy A Dunn	WAPA	1	In Favor	
Louise McCarren	WECC	10	In Favor	
Gregory L	Xcel Energy, Inc.	1	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
Pieper				
Liam Noailles	Xcel Energy, Inc.	5	In Favor	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Mark Peters	Ameren Services	3	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Robert Smith	Duke Energy	5	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	
Walter Yeager	Duke Energy Carolina	6	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric	1	Opposed	

Voter	Entity	Segment	P 404 VSL changes	Comments
	Cooperative Assoc.			
Anthony L Wilson	Georgia Power Co.	3	Opposed	
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
Mace Hunter	Lakeland Electric	3	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
Gregory Campoli	NYISO	2	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Douglas G Peterchuck	Omaha Public Power District	1	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A. Heimbach	PPL Generation LLC	5	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	

Voter	Entity	Segment	P 404 VSL changes	Comments
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Linda Horn	Wisconsin Electric Power Co.	5	Opposed	
James R. Keller	Wisconsin Electric Power Marketing	3	Opposed	
Anthony Jankowski	Wisconsin Energy Corp.	4	Opposed	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Opposed	ARGC should be ARC in one of the VSLs.
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we believe the changes for paragraph 404 exceed what is actually required in the directive, we cannot support the changes to the VSLs.
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	Missed deleting a "G" in the Severe VSL for R7
Walt Gill	Lake Worth	1	In Favor	

Voter	Entity	Segment	P 404 VSL changes	Comments
	Utilities			
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	o The proposed changes exceed the Commission directive. The directive is to change the title not throughout the entire document, it was not to change the definition of AGC. o The requestor would have been more correct if the proposal were to change the title from Automatic Generation Control to something as simple as “Area Control Error” or “Balancing Control”. o As proposed, any automatic process used in balancing would come under this umbrella. For example, if a BA used UFLS resources to help maintain its ACE, then by this definition UFLS would be AGC. o The term AGC should be considered for removal. There is no one control system - indeed many if not all control systems have their unique characteristics. What the standard mandates is the calculation and use of Area Control Error (ACE). o AGC is a generic industry term for a control process and not specific to any one resource. It is a term used by vendors and academics and Control Theory books. Thus AGC programs do have meaning to those outside our standard process, and those who service our control programs. o Regarding the proposed conforming changes to the first sentence of the definition of regulating Reserve, we question the need for the second sentence in the definition. o The FERC mandate is that DSM explicitly be allowed to provide regulating reserves. The SAR requestor proposes to meet this directive by inserting DSM into a list in the definition itself. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used.
Jeff Nelson	Springfield Utility Board	3	Opposed	Please refer to SUB's comment form
Guy Andrews	Georgia System Operations Corporation	4	Opposed	Refer to comments in paragraph 404.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	
Harold Taylor, II	GTC	1	Opposed	Refer to comments in Paragraph 404.
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	See FE comments on paragraph item 404.

Voter	Entity	Segment	P 404 VSL changes	Comments
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Opposed	The compliance section indicates that data shall be ready to be supplied however, there is no requriement to retain the data. "Balancing Authorities shall be prepared to supply data to NERC and their Regional Entity in the format defined below:" In addition, the standrad uses the term NERC rather than ERO as is the case in BAL-002. This implies a subtle difference but it is not clear what that difference is.
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	The GOP and LSE requirements are not defined in the Compliance Monitoring or VSL sections.
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P415:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 415	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	APPA	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	

Voter	Entity	Segment	P 415	Comments
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Saurabh Saksena	National Grid	1	Abstain	

Voter	Entity	Segment	P 415	Comments
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	

Voter	Entity	Segment	P 415	Comments
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	BPA	6	Approve	
Donald S. Watkins	BPA	1	Approve	
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Randall	City of Vero Beach	1	Approve	

Voter	Entity	Segment	P 415	Comments
McCamish				
Danny McDaniel	Cleco Power LLC	1	Approve	
Bryan Y Harper	Cleco Utility Group	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Brenda Powell	Constellation	6	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	

Voter	Entity	Segment	P 415	Comments
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Donald Gilbert	JEA	5	Approve	
Charles Locke	KCPL	3	Approve	
Michael Gammon	KCPL	1	Approve	

Voter	Entity	Segment	P 415	Comments
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Brad Jones	Luminant Energy	6	Approve	
Mike Laney	Luminant Generation Co. LLC	5	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
Margaret	Pacific Northwest Generating	8	Approve	

Voter	Entity	Segment	P 415	Comments
Ryan	Cooperative			
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie	Public Service Co.	1	Approve	

Voter	Entity	Segment	P 415	Comments
Williams	of New Mexico			
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	

Voter	Entity	Segment	P 415	Comments
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	

Voter	Entity	Segment	P 415	Comments
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	
Louise McCarren	WECC	10	Approve	
David F. Lemmons	Xcel Energy, Inc.	6	Approve	
Gregory L Pieper	Xcel Energy, Inc.	1	Approve	
Liam Noailles	Xcel Energy, Inc.	5	Approve	
Kirit S. Shah	Ameren Services	1	Disapprove	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	

Voter	Entity	Segment	P 415	Comments
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Mace Hunter	Lakeland Electric	3	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Dan R. Schoenecker	MRO	10	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Bruce	OTP Wholesale	6	Disapprove	

Voter	Entity	Segment	P 415	Comments
Glorvigen	Marketing			
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	"reporting or compliance" should be removed from R17 because we're not sure what that means. Who is the system operator here, the BA? Seems very confusing.
Greg C Parent	Manitoba Hydro	3	Disapprove	415 - The text in R17 should be amended to remove ..."or provide real-time error or frequency information to the system operator". The only frequency devices that need to meet the accuracy requirements are those that feed into the ACE calculation.
R Scott S. Barfield-	Georgia System Operations	3	Approve	BAL005 R5 is grammatically incorrect. Also we suggest removing the non-firm transmission language

Voter	Entity	Segment	P 415	Comments
McGinnis	Corporation			as it doesn’t add to the requirement. Stating it is no longer deliverable should suffice.
Harold Taylor, II	GTC	1	Approve	
Guy Andrews	Georgia System Operations Corporation	4	Approve	
Alan Gale	City of Tallahassee	5	Abstain	Certain Time/Frequency devices do not require calibration as stated by the manufacture. The standard makes no provision for this occurance. This will result in an interpretation request.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input into the standard development but only as part of the five year review process. Therefore, there is no need to short circuit the NERC standards development process to make changes that should be handled through the five year review of the standard for a directive that has already been met. Furthermore, the proposed changes to R17 actually contradicts the interpretation. Specifically, the interpretation was clear that the devices that needed to be calibrated are those devices that feed ACE and time error calculations. The proposed changes include any device that provides frequency information to the operator through the clause “or frequency information to the operator”. At a minimum, this clause needs to be struck.Modifying sub-requirement R17.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission’s ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: “Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes.” Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Gregory Campoli	NYISO	2	Disapprove	Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input

Voter	Entity	Segment	P 415	Comments
				into the standard development but only as part of the five year review process. o The proposed change introduces an undefined term “common reference”.
Charles H Yeung	Southwest Power Pool	2	Disapprove	Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input into the standard development but only as part of the five year review process.
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Disapprove	Disagree with proposed rewrite of R17. The use of the word “common” within common reference does not improve reliability. There are no common reference devices within the utility industry. This requirement is required to be written for all applicable entities to follow. Since there are many different frequency devices used (from satellite synched GPS receivers to 120 volt plug in models) within the industry, “common” needs to be replaced with “suitable” reference. This will allow applicable entities to calibrate their frequency devices as the manufacture recommends and thus, will improve reliability.
David A. Lapinski	Consumers Energy	3	Disapprove	In R17, the phrase "or frequency information to the operator" should be deleted as an unnecessary expansion of scope.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. NERC should find an alternate method to address the Commissions’ concern rather than simply “renaming” a widely, industry accepted and understood definition and concept such as “AGC.”
Terry L. Blackwell	Santee Cooper	1	Approve	Most frequency devices today receive their frequency from GPS satellites which derive their frequency from the National Bureau of Standards. Therefore, there is no need for devices to be calibrated.
Tom Bowe	PJM Interconnection,	2	Disapprove	o Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input into the standard development but only as part of the five year review process. o The proposed

Voter	Entity	Segment	P 415	Comments
	L.L.C.			change introduces an undefined term “common reference”.
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 415 Metering Calibration under R17: Directives in paragraph 415 have already been met through the Interpretation currently in BAL-005-0.1b approved by the BOT and approved by the Commission in Order 713 on July 21, 2008. Furthermore, Duke Energy disagrees with the language in the proposed R17, as it does not address the concerns noted in Paragraph 415 and deviates from the Interpretation approved by the Commission which states: " As noted in the existing interpretation, BAL-005-1 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements. New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy."The Interpretation was clear that "Frequency inputs from other sources that are for reference only are excluded", however the proposed language "or frequency information to the system operator" could be interpreted to include such devices that the Commission-approved Interpretation specifically excluded. Without qualifying language to clearly focus on only those devices applicable in the Interpretation, be believe this is a step backwards from the guidance currently provided. At a minimum, this clause needs to be struck or clarified to not conflict with the Interpretation.The proposed language also does not include the points in the Interpretation that address the concerns in Paragraph 415, which is the accommodation of newer technology what may be needed for newer devices by allowing them to be cross-checked against other properly calibrated equipment. Further, the existing standard and approved interpretations do not specify the timeframe for replacement or re-calibration.Original Tiger Team proposed changes:R17. Each Balancing Authority shall at least annually verify against a common reference the calibration of its frequency devices that provide input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator.R17.1. If the calibration of a frequency device described above is found to not be accurate within +/- 0.001 Hz, the Balancing Authority shall within 60 calendar days either: o Calibrate the device to within +/- 0.001 Hz, or o Replace the

Voter	Entity	Segment	P 415	Comments
				deviceProposed Acceptable ChangesR17. Regarding the calibration of the Balancing Authority's frequency devices that provide input into the calculation of ACE or provide real-time time error to the system operator, and excluding those frequency devices used for reference only, at least annually each Balancing Authority shall either a) verify the device accuracy against a common reference or b) cross-check the device accuracy against other properly calibrated equipment.R17.1. If the calibration of a frequency device described above is found not to be accurate within +/- 0.001 Hz, the Balancing Authority shall either: o Calibrate the device to within +/- 0.001 Hz, or o Replace the deviceIn addition, all changes by the Tiger Team to the Violation Severity Levels matrix should be deleted. The VSL matrix for R17 should be returned to its original approved state.
Jeff Nelson	Springfield Utility Board	3	Disapprove	Please refer to SUB's comment form
Kim Warren	IESO	2	Disapprove	R17 says "Verify against a common reference", however it gives no indication of what an appropriate common reference is. Does this mean an entity can calibrate and check its primary frequency device against its backup? We imagine not. Clarification on the intent of this requirement would be appreciated as "common reference" is vague.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	Significant portions of the Interpretation are missing. The statement "Frequency inputs from other sources that are for reference only are excluded." Needs to be part of the standard. Without that statement, all frequency devices of any accuracy that provide real-time data to the operator must be of the stated accuracy and must be calibrated. The phrase "real-time error" in R17 is not clear. What error? For R17.1, R8.1 already requires independent and redundant frequency metering equipment. From our experience it is impossible to get a True Time device calibrated within 60 days. The only way for a BA to comply with R17.1 is to have a spare annually calibrated device (or possibly two) on the shelf available to replace a failed device.
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Doug Bantam	LES	1	Disapprove	Since there are many different frequency devices used (from satellite synched GPS receivers to 120 volt plug in models) within the industry, "common" needs to be replaced with "suitable" reference. This will allow applicable entities to calibrate their frequency devices as the manufacture recommends and thus, will improve reliability
Dennis Florom	LES	5	Disapprove	
Eric Ruskamp	LES	6	Disapprove	
Richard J. Mandes	Alabama Power Co.	3	Approve	Taken from previously posted interpretation in Appendix 1.
Anthony L	Georgia Power Co.	3	Approve	

Voter	Entity	Segment	P 415	Comments
Wilson				
Gwen S Frazier	Gulf Power Co.	3	Approve	
Don Horsley	Mississippi Power	3	Approve	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Approve	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	The changes make rhe requirement excessively prestictive. Requirements should be object oriented, i.e. specify what is to be achieved and not how to achieve the objective.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Daniel Herring	Detroit Edison Co.	4	Disapprove	The Commission approved interpretation is very clear on qualifying frequency devices while the proposed change is ambiguous.
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	The directives in 415 and 420 have already been met and the proposed modification does not improve reliability. A superior BAL-005-0.1b interpretation has already addressed paragraph 415. R17 should be modified to say the following which is consistent with the BAL-005-0.1b interpretation, "Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements. New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy." The proposed R17 clause should not be adopted. The proposed requirement to replace equipment in 60 days is unrealistic and beyond the

Voter	Entity	Segment	P 415	Comments
				paragraph 415 directive.
Kevin Koloini	American Municipal Power - Ohio	4	Approve	The GOP and LSE requirements are not defined in the Compliance Monitoring or VSL sections.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	The proposed revision to R17 and removal of a FERC approved interpretation from the standard require further consideration by the industry and should not be considered "low hanging fruit". Further, R17 is a BA requirement and FE generally supports the MISO and PJM positions (BA entities for FE footprint) for this item.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Michelle Rheault	Manitoba Hydro	1	Approve	The text in R17 should be amended to remove ..."or provide real-time error or frequency information to the system operator". The only frequency devices that need to meet the accuracy requirements are those that feed into the ACE calculation.
Daniel Prowse	Manitoba Hydro	6	Disapprove	
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	We would encourage NERC to find an alternate method to address the Commissions' concern rather than simply "renaming" a widely, industry-accepted and understood definition and concept such as "AGC."

Voter	Entity	Segment	P 415 VSL changes	Comments
Raj Rana	AEP	3	In Favor	
Edward P. Cox	AEP Marketing	6	In Favor	
Brock Ondayko	AEP Service Corp.	5	In Favor	
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	In Favor	
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	The GOP and LSE requirements are not defined in the Compliance Monitoring or VSL sections.
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Donald S. Watkins	BPA	1	In Favor	
Rebecca Berdahl	BPA	3	In Favor	
Francis J. Halpin	BPA	5	In Favor	
John Yale	Chelan County Public Utility	5	In Favor	

Voter	Entity	Segment	P 415 VSL changes	Comments
	District #1			
Linda R. Jacobson	City of Farmington	3	In Favor	
Gregg R Griffin	City of Green Cove Springs	3	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Brenda Powell	Constellation	6	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	In Favor	
David A. Lapinski	Consumers Energy	3	In Favor	
David Frank Ronk	Consumers Energy	4	In Favor	
James B Lewis	Consumers Energy	5	In Favor	
Russell A Noble	Cowlitz County PUD	3	In Favor	
Daniel Herring	Detroit Edison Co.	4	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	

Voter	Entity	Segment	P 415 VSL changes	Comments
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	In Favor	
George R. Bartlett	Entergy Corporation	1	In Favor	
Stanley M Jaskot	Entergy Corporation	5	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	In Favor	
Guy Andrews	Georgia System Operations	4	In Favor	

Voter	Entity	Segment	P 415 VSL changes	Comments
	Corporation			
Harold Taylor, II	GTC	1	In Favor	
Gwen S Frazier	Gulf Power Co.	3	In Favor	
Kim Warren	IESO	2	In Favor	Provided changes are made to R17 to address our comment.
Donald Gilbert	JEA	5	In Favor	
Michael Gammon	KCPL	1	In Favor	
Charles Locke	KCPL	3	In Favor	
Walt Gill	Lake Worth Utilities	1	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Daniel Duff	Liberty Electric Power LLC	5	In Favor	
Brad Jones	Luminant Energy	6	In Favor	
Mike Laney	Luminant Generation Co. LLC	5	In Favor	
Daniel Prowse	Manitoba Hydro	6	In Favor	
Steven M. Jackson	MEAG	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	

Voter	Entity	Segment	P 415 VSL changes	Comments
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
John C. Collins	Platte River Power Authority	1	In Favor	

Voter	Entity	Segment	P 415 VSL changes	Comments
Terry L Baker	Platte River Power Authority	3	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Laurie Williams	Public Service Co. of New Mexico	1	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	

Voter	Entity	Segment	P 415 VSL changes	Comments
Trent Carlson	RRI Energy	6	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
Terry L. Blackwell	Santee Cooper	1	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Dennis Sismaet	Seattle City Light	6	In Favor	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	In Favor	
Tim Kelley	SMUD	1	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Mike Ramirez	SMUD	4	In Favor	
Bethany Wright	SMUD	5	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
Steve McElhaney	South Mississippi Electric Power Association	4	In Favor	
Jerry W Johnson	South Mississippi Electric Power	5	In Favor	

Voter	Entity	Segment	P 415 VSL changes	Comments
	Association			
Richard McLeon	South Texas Electric Cooperative	1	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
George T. Ballew	Tennessee Valley Authority	5	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
Jonathan Appelbaum	United Illuminating Co.	1	In Favor	
Brandy A Dunn	WAPA	1	In Favor	
Louise McCarren	WECC	10	In Favor	
Liam Noailles	Xcel Energy, Inc.	5	In Favor	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Alan Gale	City of Tallahassee	5	Opposed	
Robert W.	Dairyland Power	1	Opposed	

Voter	Entity	Segment	P 415 VSL changes	Comments
Roddy	Coop.			
Robert Smith	Duke Energy	5	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	
Walter Yeager	Duke Energy Carolina	6	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	See FE comments on paragraph item 415.
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Rex A Roehl	Indeck Energy Services, Inc.	5	Opposed	
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.

Voter	Entity	Segment	P 415 VSL changes	Comments
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
Mace Hunter	Lakeland Electric	3	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 415 in their current format, we cannot support the changes to the VSLs.
John Bos	Muscatine Power & Water	3	Opposed	
Gregory Campoli	NYISO	2	Opposed	
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	See FE comments on paragraph item 415.
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	o Directives in paragraph 415 have already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard interpretations definitely should be used as input into the standard development but only as part of the five year review process. o The proposed change introduces an undefined term “common reference”.
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A.	PPL Generation LLC	5	Opposed	

Voter	Entity	Segment	P 415 VSL changes	Comments
Heimbach				
Daniel Baerman	San Diego G&E	5	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
Jeff Nelson	Springfield Utility Board	3	Opposed	Please refer to SUB's comment form
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Linda Horn	Wisconsin Electric Power Co.	5	Opposed	
James R. Keller	Wisconsin Electric Power Marketing	3	Opposed	
Anthony Jankowski	Wisconsin Energy Corp.	4	Opposed	
Gregory L Pieper	Xcel Energy, Inc.	1	Opposed	
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P420:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 420	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	APPA	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Doug Ramey	Energy Northwest - Columbia	5	Abstain	

Voter	Entity	Segment	P 420	Comments
	Generating Station			
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Saurabh Saksena	National Grid	1	Abstain	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	

Voter	Entity	Segment	P 420	Comments
Ronald Schloendorn	PECO Energy	1	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	

Voter	Entity	Segment	P 420	Comments
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	BPA	6	Approve	
Donald S. Watkins	BPA	1	Approve	
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Danny McDaniel	Cleco Power LLC	1	Approve	
Bryan Y Harper	Cleco Utility Group	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Brenda Powell	Constellation	6	Approve	
Carolyn	Constellation	3	Approve	

Voter	Entity	Segment	P 420	Comments
Ingersoll	Energy			
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Dan Roethemeyer	Dynegy Inc.	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	

Voter	Entity	Segment	P 420	Comments
Donald Gilbert	JEA	5	Approve	
Charles Locke	KCPL	3	Approve	
Michael Gammon	KCPL	1	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Brad Jones	Luminant Energy	6	Approve	
Mike Laney	Luminant Generation Co. LLC	5	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Dan R. Schoenecker	MRO	10	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	

Voter	Entity	Segment	P 420	Comments
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C.	Platte River Power	1	Approve	

Voter	Entity	Segment	P 420	Comments
Collins	Authority			
Frank F. Afranji	Portland General Electric Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	

Voter	Entity	Segment	P 420	Comments
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric	1	Approve	

Voter	Entity	Segment	P 420	Comments
	Cooperative			
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	
Louise McCarren	WECC	10	Approve	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S.	East Kentucky	1	Disapprove	

Voter	Entity	Segment	P 420	Comments
Carruba	Power Coop.			
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Mace Hunter	Lakeland Electric	3	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	

Voter	Entity	Segment	P 420	Comments
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L	Xcel Energy, Inc.	1	Disapprove	

Voter	Entity	Segment	P 420	Comments
Pieper				
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	7)Under Compliance 1.1 it refers to “their” Regional Entity. However, 1.1.1. refers to “the” Regional Entity. We recommend consistency. Also as a general statement the use of the term Regional Entity (RE) vs. Regional Reliability Organization (RRO) should be reviewed in all of these documents to ensure consistency.
James V. Petrella	Atlantic City Electric Co.	3	Disapprove	A BA does not monitor transmission constraints. Other standards already require a BA to follow the directions of a TOP or RC. This change is not needed.
Richard J Kafka	Potomac Electric Power Co.	1	Disapprove	
Terry L. Blackwell	Santee Cooper	1	Disapprove	Any changes to NERC definitions should follow the ANSI approved standards process.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	As written, the change from AGC to ARC makes the BA responsible in standards compliance for DSM actions of an LSE or end-use customer but does not give the BA any authority in the DSM actions of the LSE or end-use customer. What is the effect of the change from AGC to ARC in all the other FERC approved standards?
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Jason Shaver	ATC	1	Disapprove	ATC believes that this requirement should be limited to only those devices that feed into the ACE equation and not be expanded any devices that sole supply real-time error or frequency information.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Kim Warren	IESO	2	Disapprove	For the first part of changes for directive in Paragraph 420 involving defining ARC, please see our comment on the definition of ARC.Wrt the latter part of directive in Paragraph 420, we do not think the proposed changes to R5 fully address the directive, which asks the ERO to “specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service.” The proposed changes to R5 describe the conditions (and causes for)

Voter	Entity	Segment	P 420	Comments
				that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this requirement be further developed, preferably by the BACSDT.
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	In addition to our comment to Paragraph 404 we have the following: Paragraph 420 - Addressing Non-Firm Transmission Service: Duke Energy disagrees with the proposed language as Regulation Service could also be rendered unavailable due to transmission constraints impacting Firm transmission service; however a more important issue relates to the implementation of Regulation Service if on Non-Firm transmission service. In general Duke Energy disagrees with allowing Regulation Service to be provided on Non-Firm transmission service as there are no rules requiring such service on Non-Firm transmission to be implemented as a Dynamic Schedule (rather than a Pseudo-Tie) where it would be subject to the Standards applicable to Scheduled Interchange including e-tagging and Non-Firm transmission curtailment. We would propose striking the last part of the sentence to address the FERC's deliverability issue but allow the firm/non-firm discussion to be addressed at a later time: "R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should either the supplying Balancing Authority no longer be able to provide this service or the service is no longer deliverable due to transmission constraints."Paragraph 420 - Redundancy in terms in the Regulated Reserve definition where “controllable load” will suffice: Duke Energy disagrees with splitting out DSM as a separate resource as the qualification criteria would have it fall under the category of "controllable load resource" available to the Balancing Authority. We would propose striking it from the sentence:"Regulating Reserve may be comprised of generation, controllable load resources, or other resources that have comparable response characteristics"General Suggestion for Requirement R5 text:Requirement R5 has a grammar problem (verb tense consistency) - change "or the service is no longer deliverable" to "or the service be no longer deliverable".
Timothy VanBlaricom	California ISO	2	Disapprove	In the definition of Regulating Reserve we feel that 'comparable response characteristics' is not appropriate and vague. All the resources just need to be responsive to ARC and sufficient to provide normal regulating margin. There is no response characteristic required
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a “HOW” to meet the requirements instead of “WHAT” to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to

Voter	Entity	Segment	P 420	Comments
				enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. NERC should find an alternate method to address the Commissions' concern rather than simply "renaming" a widely, industry accepted and understood definition and concept such as "AGC."
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	no regulation reserves in DSM. only direct control load management
Michael F Gildea	Dominion Resources Services	3	Abstain	Paragraph 420 - While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be desired to assure reliability. We note that FERC did not require NERC revise the standard to allow the use of non-firm transmission service and believe that further stakeholder vetting of this is superior to the proposed revision to the standard. In the last sentence, "nonfarm" should be "non-firm."
Louis S Slade	Dominion Resources, Inc.	6	Abstain	
John K Loftis	Dominion Virginia Power	1	Abstain	
Jeff Nelson	Springfield Utility Board	3	Disapprove	Please refer to SUB's comment form
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	R5 doesn't read right; "be" should be removed and "is" should be inserted before the first "no".Some additonal changes were made to the standard beyond the 693 directives and the Revision History should reflect that.
Gregory Campoli	NYISO	2	Disapprove	R5 imposes transmission-based responsibilities on the BA. That is simply wrong. The BA must plan and operate within the transmission constraints imposed by its TOPs. The proposed changes to R5 do not fully address the issues involved with the directive, which asks the ERO to "specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service." The proposed changes to R5 describe the conditions (and causes for) that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this requirement be further developed, preferably by the BACSDT. Note a better solution would be to end the R5 requirement after the phrase "...provide replacement Regulation Service."
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	R5 imposes transmission-based responsibilities on the BA. That is simply wrong. The BA must plan and operate within the transmission constraints imposed by its TOPs. The proposed changes to R5 do not fully address the issues involved with the directive, which asks the ERO to "specify the required type of transmission or backup plans when receiving regulation from outside the balancing

Voter	Entity	Segment	P 420	Comments
				authority when using non-firm service." The proposed changes to R5 describe the conditions (and causes for) that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this requirement be further developed, preferably by the BACSDT. Note a better solution would be to end the R5 requirement after the phrase "...provide replacement Regulation Service."
Randall McCamish	City of Vero Beach	1	Disapprove	Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative in the definition of Regulating Reserve.
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	Regulation Reserve should not include any type DSM, but rather only Direct Control Load Management (DCLM, i.e., DSM under the direct control of the System Operator). Regulation reserve is too important to not have direct System Operator control. Also, "DSM" and "controllable load resources" are duplicative in the definition of Regulating Reserve.
Kirit S. Shah	Ameren Services	1	Disapprove	Retail Customer(b) The proposed ARC definition should modify "Balancing Authority's interchange..." to "Balancing Authority Area's interchange ...", since BA does not have a schedulem rather a BAA does (e.g. one BA may operate multiple BAA). (c) In the Regulating Reserve definition add "to generation resources" between comparable and response in the last phrase. (d)In R7, the team uses ARC but refers to generation. (e)In R5 - No regulating reserve should be on non-firm service
Mark Peters	Ameren Services	3	Disapprove	
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	See comment for item 404 related to the AGC to ARC change.FE supports MISO's position on the proposed changes for R5.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	See comment on para. 404
Richard J. Mandes	Alabama Power Co.	3	Approve	Seems reasonable to have a backup plan for lost regulation service due totransmission constraints.

Voter	Entity	Segment	P 420	Comments
Anthony L Wilson	Georgia Power Co.	3	Approve	
Gwen S Frazier	Gulf Power Co.	3	Approve	
Don Horsley	Mississippi Power	3	Approve	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Approve	Seems reasonable to have a backup plan for lost regulation service due to transmission constraints.
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	The changes make rhe requirement excessively prestictive. Requirements should be object oriented, i.e. specify what is to be achieved and not how to achieve the objective.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	The Directive in paragraph 415 has already been met through the interpretation b approved by the Commission in Order 713 on July 21, 2008. Standard Interpretations should be used as input into the standard development but only as part of the five year review process. Also, this proposed change unnecessarily introduces an undefined term “common reference.”
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	The directives in Paragraph 420 have already been addressed in BAL-005-0-R5 implicitly. R5 requires that backup plans are in place when a BA is no longer able provide service, which includes transmission constraints. The proposed modification does not improve reliability or clarity and should be dropped. NERC can state the directive was already addressed.
Kevin Koloini	American Municipal Power - Ohio	4	Approve	The GOP and LSE requirements are not defined in the Compliance Monitoring or VSL sections.
Charles H Yeung	Southwest Power Pool	2	Disapprove	The proposed changes to R5 do not fully address the issues involved with the directive, which asks the ERO to “specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service.” The proposed changes to R5 describe the conditions (and causes for) that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this

Voter	Entity	Segment	P 420	Comments
				requirement be further developed, preferably by the BACSDT. Note a better solution would be to end the R5 requirement after the phrase “...provide replacement Regulation Service.”
George T. Ballew	Tennessee Valley Authority	5	Disapprove	This solution may not be as comprehensive as would be desired to assure reliability. In the last sentence, "nonfarm" should be "non-firm".
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be needed to assure reliability. In the last sentence, "nonfarm" should be "non-firm".
Harold Taylor, II	GTC	1	Disapprove	Under Compliance 1.1 it refers to “their” Regional Entity. However, 1.1.1. refers to “the” Regional Entity. We recommend consistency. Also as a general statement the use of the term Regional Entity (RE) vs. Regional Reliability Organization (RRO) should be reviewed in all of these documents to ensure consistency.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	Under Compliance 1.1 it refers to “their” Regional Entity. However, 1.1.1. refers to “the” Regional Entity. We recommend consistency. Also as a general statement the use of the term Regional Entity (RE)vs. Regional Reliability Organization (RRO) should be reviewed in all of these documents to ensure consistency.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We disagree with the changes to R5. First, the existing R5 already considers transmission constraints implicitly by stating “shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.” “Transmission constraints” is just one of a litany of reasons that the supplying Balancing Authority may not be able to provide regulation service. Why should transmission constraints be singled out as a reason? Secondly, BAL-001-0.1a still applies to the receiving BA regardless. That is, the receiving BA still must meet CPS1 and CPS2 regardless of why the regulation service is no longer available. We believe NERC simply needs the assistance of drafting team to explain the technical reasons why this is already addressed in the existing requirement.
Mike Garton	Dominion Resources, Inc.	5	Abstain	While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be desired to assure reliability. We note that FERC did not require NERC revise the standard to allow the use of non-firm transmission service and believe that further stakeholder vetting of this is superior to the proposed revision to the standard. In the last sentence, “nonfarm” should be “non-firm.”
George R. Bartlett	Entergy Corporation	1	Disapprove	While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be needed to assure reliability. The Balancing Authority receiving Regulation

Voter	Entity	Segment	P 420	Comments
Stanley M Jaskot	Entergy Corporation	5	Disapprove	Service should be required to ensure that backup plans are in place to provide replacement Regulation Service should the service no longer be deliverable due to transmission constraints impacting the service, whether firm or non-firm. This change would meet the intent of the Commission directive, and improve reliability by ensuring backup plans exist.
Larry Akens	Tennessee Valley Authority	1	Disapprove	While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be needed to assure reliability. In the last sentence, "nonfarm" should be "non-firm".

Voter	Entity	Segment	P 420 VSL changes	Comments
Raj Rana	AEP	3	In Favor	
Edward P. Cox	AEP Marketing	6	In Favor	
Brock Ondayko	AEP Service Corp.	5	In Favor	
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Donald S. Watkins	BPA	1	In Favor	
Francis J. Halpin	BPA	5	In Favor	
Rebecca Berdahl	BPA	3	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	

Voter	Entity	Segment	P 420 VSL changes	Comments
Gregg R Griffin	City of Green Cove Springs	3	In Favor	
Alan Gale	City of Tallahassee	5	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Brenda Powell	Constellation	6	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	In Favor	
David A. Lapinski	Consumers Energy	3	In Favor	
David Frank Ronk	Consumers Energy	4	In Favor	
James B Lewis	Consumers Energy	5	In Favor	
Russell A Noble	Cowlitz County PUD	3	In Favor	
Daniel Herring	Detroit Edison Co.	4	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	

Voter	Entity	Segment	P 420 VSL changes	Comments
Doug Ramey	Energy Northwest - Columbia Generating Station	5	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Donald Gilbert	JEA	5	In Favor	
Charles Locke	KCPL	3	In Favor	
Michael Gammon	KCPL	1	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Doug Bantam	LES	1	In Favor	
Dennis Florom	LES	5	In Favor	
Eric Ruskamp	LES	6	In Favor	
Brad Jones	Luminant Energy	6	In Favor	
Mike Laney	Luminant Generation Co. LLC	5	In Favor	
Steven M.	MEAG	3	In Favor	

Voter	Entity	Segment	P 420 VSL changes	Comments
Jackson				
Steven Grego	MEAG Power	3	In Favor	
John Bos	Muscatine Power & Water	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	In Favor	
John Apperson	PacifiCorp	3	In Favor	

Voter	Entity	Segment	P 420 VSL changes	Comments
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Terry L Baker	Platte River Power Authority	3	In Favor	
John C. Collins	Platte River Power Authority	1	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Laurie Williams	Public Service Co. of New Mexico	1	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D.	Public Utility	4	In Favor	

Voter	Entity	Segment	P 420 VSL changes	Comments
Martinsen	District No. 1 of Snohomish County			
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
John T. Underhill	Salt River Project	3	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Dennis Sismaet	Seattle City Light	6	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	In Favor	
Bethany Wright	SMUD	5	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Mike Ramirez	SMUD	4	In Favor	
Tim Kelley	SMUD	1	In Favor	

Voter	Entity	Segment	P 420 VSL changes	Comments
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
Steve McElhaney	South Mississippi Electric Power Association	4	In Favor	
Jerry W Johnson	South Mississippi Electric Power Association	5	In Favor	
Richard McLeon	South Texas Electric Cooperative	1	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
Jonathan Appelbaum	United Illuminating Co.	1	In Favor	
Brandy A Dunn	WAPA	1	In Favor	
Louise McCarren	WECC	10	In Favor	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine	1	Opposed	

Voter	Entity	Segment	P 420 VSL changes	Comments
	Power Co.			
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Robert Smith	Duke Energy	5	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
George R. Bartlett	Entergy Corporation	1	Opposed	
Stanley M Jaskot	Entergy Corporation	5	Opposed	
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	

Voter	Entity	Segment	P 420 VSL changes	Comments
Mace Hunter	Lakeland Electric	3	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Gregory Campoli	NYISO	2	Opposed	
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A. Heimbach	PPL Generation LLC	5	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	
Terry L. Blackwell	Santee Cooper	1	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	

Voter	Entity	Segment	P 420 VSL changes	Comments
Jeff Nelson	Springfield Utility Board	3	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
George T. Ballew	Tennessee Valley Authority	5	Opposed	
Linda Horn	Wisconsin Electric Power Co.	5	Opposed	
James R. Keller	Wisconsin Electric Power Marketing	3	Opposed	
Anthony Jankowski	Wisconsin Energy Corp.	4	Opposed	
Gregory L Pieper	Xcel Energy, Inc.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 420 in their current format, we cannot support the changes to the VSLs.
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	Missed deleting a "G" in the Severe VSL for R7
Walt Gill	Lake Worth Utilities	1	In Favor	Missed deleting a "G" in the Severe VSL for R7

Voter	Entity	Segment	P 420 VSL changes	Comments
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	R5 imposes transmission-based responsibilities on the BA. That is simply wrong. The BA must plan and operate within the transmission constraints imposed by its TOPs. The proposed changes to R5 do not fully address the issues involved with the directive, which asks the ERO to “specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service.” The proposed changes to R5 describe the conditions (and causes for) that require replacing Regulating Reserve. These are not the type of transmission or backup plans with any specificity. In our view, the specific type of transmission or backup plans include such measures as acquiring higher priority transmission services, initiating curtailment to free up transmission, or engaging in additional unit commitment, etc. We suggest this requirement be further developed, preferably by the BACSDT. Note a better solution would be to end the R5 requirement after the phrase “...provide replacement Regulation Service.”
Kim Warren	IESO	2	Opposed	R5 needs to be revised first.
Guy Andrews	Georgia System Operations Corporation	4	Opposed	Refer to comments in paragraph 420.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	
Harold Taylor, II	GTC	1	Opposed	
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	The GOP and LSE requirements are not defined in the Compliance Monitoring or VSL sections.
Rex A Roehl	Indeck Energy Services, Inc.	5	In Favor	Typo in VSL R7 "ARGC"
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P565:

The Response Team has considered the comments received on these modifications and determined that the directive has already been addressed in a previous revision to the standard.

Upon Board approval of the remaining balloted and approved standards, this determination will be included in the filing presented to FERC regarding the other standards.

Voter	Entity	Segment	P 565	Comments
Allen Mosher	APPA	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country	5	Abstain	

Voter	Entity	Segment	P 565	Comments
	Energy			
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Thomas J. Bradish	RRI Energy	5	Abstain	
Trent Carlson	RRI Energy	6	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	

Voter	Entity	Segment	P 565	Comments
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Richard J. Mandes	Alabama Power Co.	3	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
Brenda S. Anderson	BPA	6	Approve	
Donald S. Watkins	BPA	1	Approve	
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	

Voter	Entity	Segment	P 565	Comments
Randall McCamish	City of Vero Beach	1	Approve	
Danny McDaniel	Cleco Power LLC	1	Approve	
Bryan Y Harper	Cleco Utility Group	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
Robert Smith	Duke Energy	5	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	

Voter	Entity	Segment	P 565	Comments
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	
Kenneth Dresner	FirstEnergy Solutions	5	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Anthony L Wilson	Georgia Power Co.	3	Approve	

Voter	Entity	Segment	P 565	Comments
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Harold Taylor, II	GTC	1	Approve	
Gwen S Frazier	Gulf Power Co.	3	Approve	
Ajay Garg	Hydro One Networks, Inc.	1	Approve	
Michael D. Penstone	Hydro One Networks, Inc.	3	Approve	
Donald Gilbert	JEA	5	Approve	
Charles Locke	KCPL	3	Approve	
Michael Gammon	KCPL	1	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
John W Delucca	Lee County Electric Cooperative	1	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Approve	
Charlie Martin	Louisville Gas and	5	Approve	

Voter	Entity	Segment	P 565	Comments
	Electric Co.			
Daryn Barker	Louisville Gas and Electric Co.	6	Approve	
Brad Jones	Luminant Energy	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Jason L Marshall	Midwest ISO, Inc.	2	Approve	
Don Horsley	Mississippi Power	3	Approve	
Dan R. Schoenecker	MRO	10	Approve	
John Bos	Muscatine Power & Water	3	Approve	
Saurabh Saksena	National Grid	1	Approve	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Approve	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	

Voter	Entity	Segment	P 565	Comments
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Tim Hattaway	PowerSouth Energy Cooperative	5	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	

Voter	Entity	Segment	P 565	Comments
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	

Voter	Entity	Segment	P 565	Comments
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Approve	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	

Voter	Entity	Segment	P 565	Comments
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	

Voter	Entity	Segment	P 565	Comments
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	"if appropriate" terminology in R4 leaves room for interpretation and should be removed or defined.
Kirit S. Shah	Ameren Services	1	Disapprove	(a) R1 should include the recent interpretation. (b) Section A.5 - As the requirement R5, requires the emergency plan to be updated and reviewed annually, having an effective date that is less than a year away might result in a review between the annual reviews. if the effective date was the first day of the first calender quarter one year after approval, no extra reviews/update would be necessary.
Gregory Campoli	NYISO	2	Disapprove	Although the proposed language in R4 addresses the directive, the language is loose and leaves room for interpretation. For example, What constitutes "consider"?; The proposed revised VSLs are too vague as they contain both "consider" ad "appropriate", both of which are difficult to demonstrate or prove that the responsible entity comply with the intent of the requirement. The change introduces a need to prove that the functional entity "considered" Attachment 1. Either the change should remain and the industry should expect compliance entities to look for such proof; or the proposal
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	

Voter	Entity	Segment	P 565	Comments
				should be dropped and allow the functional entities to include only the "applicable elements". Further, the comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved. We believe that, through this effort, NERC has addressed FERC's order to "examine whether to clarify this term in the Reliability Standards development process" and that it needs no further clarification at this time. The matter, we are confident, will be fully vetted in the next iteration of this Standard.
Charles H Yeung	Southwest Power Pool	2	Disapprove	Although the proposed language in R4 addresses the directive, the language is loose and leaves room for interpretation. For example, What constitutes "consider"?; The proposed revised VSLs are too vague as they contain both "consider" ad "appropriate", both of which are difficult to demonstrate or prove that the responsible entity comply with the intent of the requirement.
Jason Shaver	ATC	1	Disapprove	ATC is voting negative on this requirement because we do not believe that the current language provides sufficient clarity. 1) Does the new language strictly apply to emergencies of insufficient generating capacity in which transmission capability is restricting generation?, or Does this standard mean that an emergency is any time transmission capability is reduced? 2) ATC believes that the team needs to provide addition detail about the TOP's responsibility to develop a mitigating operating emergencies for those whose mitigation plans are hindered by a lack of transmission capability. Who is the SDT referencing with the statement "those whose"? Would this require every TOP to demonstrate that their plans are not hindered by a lack of transmission capability?, or Does this mean that if the TOP has to included in their mitigate operating emergencies plans those BA's both within or adjacent to the TOP that have mitigation plans that are hindered by a lack of transmission capability. Lastly, what qualifies as a lack of transmission capability?
Timothy VanBlaricom	California ISO	2	Disapprove	Find 'if appropriate' vague.
Douglas E. Hils	Duke Energy Carolina	1	Approve	Paragraph 565: Standards EOP-001-2, EOP-002-3, and EOP-004-2 each have Attachments associated with them. The numbering system used to identify each Attachment needs to be modified to reflect the new EOP Standard numbers. For example, Attachment 1-EOP-001-0 needs to be changed to Attachment 1-EOP-001-2.

Voter	Entity	Segment	P 565	Comments
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	R4 includes the phrase “and if appropriate.” This phrase is vague. Who or what determines what is or isn’t appropriate?
Eric Egge	Black Hills Corp	1	Approve	R4 includes the phrase “and if appropriate.” Who or what determines what is or isn’t appropriate? This phrase is vague.
Linda R. Jacobson	City of Farmington	3	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Louise McCarren	WECC	10	Approve	R4 includes the phrase “and if appropriate.” Who or what determines what is or isn’t appropriate? This phrase is vague and will cause confusion for applicable entities. Clarifying language should be added indicating that the applicable entity is the appropriate party to determine the "apropriatness" of inclusion of applicable elements in Attachement 1-EOP-001-0 when develpoing an emergency plan.
David A. Lapinski	Consumers Energy	3	Disapprove	Relative to R4 and the VSLs presented in the draft standard, some entities (particularly those who have entered into JRO’s regarding BAL-005, but share R4 responsibilities with other entities) may not have available the ability to apply one or more of the elements in Attachment 1. However, if the entity cannot demonstrate to the satisfaction of the Compliance Monitoring Authority that they have indeed considered these elements, and have, for demonstrable cause, determined that these elements are not “appropriate”, it will likely lead to disputes with the Compliance Monitoring Authority when evaluating compliance. “Appropriate” need to be better defined in the context of both R4 and the VSLs.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	The change appears to be reasonable.
Richard J Kafka	Potomac Electric Power Co.	1	Disapprove	The change did not clarify or enhance the requirement

Voter	Entity	Segment	P 565	Comments
James V. Petrella	Atlantic City Electric Co.	3	Disapprove	
Kim Warren	IESO	2	Disapprove	The proposed language in R4, though literally addresses the directive, is loose and leaves room for interpretation as to what constitutes “consider”, and the proposed revised VSLs are too vague as they contain both “consider” ad “appropriate”, both of which are difficult to demonstrate or prove that the responsible entity comply with the intent of the requirement. More time is needed to develop a meaningful requirement and its associated compliance elements.
Brandy A Dunn	WAPA	1	Approve	The term "if appropriate" is vague. Recommend changing to "if applicable".
Scott Peterson	San Diego G&E	3	Disapprove	The VSL should be that the entity didn't consider not that the entity cannot demonstrate that it considered
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	The words "shall include applicable elements in Attachment 1 is clearly specified in R4. The proposed modifications do not enhance reliability or clarity since "applicable" is equivalent to "consideration" in this case. NERC can state that the FERC directive was considered and already addressed.
Kathleen Goodman	ISO New England, Inc.	2	Abstain	This comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agrees that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved.
David H. Boguslawski	Northeast Utilities	1	Disapprove	This comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved.
John Tolo	Tucson Electric Power Co.	1	Approve	Who or what determines what is or isn’t appropriate? This phrase is vague.

Voter	Entity	Segment	P 565 VSL changes	Comments
Raj Rana	AEP	3	In Favor	

Voter	Entity	Segment	P 565 VSL changes	Comments
Edward P. Cox	AEP Marketing	6	In Favor	
Brock Ondayko	AEP Service Corp.	5	In Favor	
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	In Favor	
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Donald S. Watkins	BPA	1	In Favor	
Francis J. Halpin	BPA	5	In Favor	
Rebecca Berdahl	BPA	3	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Gregg R Griffin	City of Green Cove Springs	3	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Paul Morland	Colorado Springs	1	In Favor	

Voter	Entity	Segment	P 565 VSL changes	Comments
	Utilities			
Carolyn Ingersoll	Constellation Energy	3	In Favor	
Russell A Noble	Cowlitz County PUD	3	In Favor	
Daniel Herring	Detroit Edison Co.	4	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Robert Smith	Duke Energy	5	In Favor	
George S. Carruba	East Kentucky Power Coop.	1	In Favor	
Sally Witt	East Kentucky Power Coop.	3	In Favor	
Stephen Ricker	East Kentucky Power Coop.	5	In Favor	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	In Favor	
George R. Bartlett	Entergy Corporation	1	In Favor	
Stanley M Jaskot	Entergy	5	In Favor	

Voter	Entity	Segment	P 565 VSL changes	Comments
	Corporation			
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Robert Martinko	FirstEnergy Energy Delivery	1	In Favor	
Kenneth Dresner	FirstEnergy Solutions	5	In Favor	
Kevin Querry	FirstEnergy Solutions	3	In Favor	
Mark S Travaglianti	FirstEnergy Solutions	6	In Favor	
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Guy Andrews	Georgia System Operations Corporation	4	In Favor	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	In Favor	
Harold Taylor, II	GTC	1	In Favor	

Voter	Entity	Segment	P 565 VSL changes	Comments
Donald Gilbert	JEA	5	In Favor	
Charles Locke	KCPL	3	In Favor	
Michael Gammon	KCPL	1	In Favor	
Walt Gill	Lake Worth Utilities	1	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Doug Bantam	LES	1	In Favor	
Dennis Florom	LES	5	In Favor	
Eric Ruskamp	LES	6	In Favor	
Steven M. Jackson	MEAG	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	
John Bos	Muscatine Power & Water	3	In Favor	
Saurabh Saksena	National Grid	1	In Favor	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Douglas Hohlbaugh	Ohio Edison Co.	4	In Favor	
Marvin E VanBebber	Oklahoma Gas and	1	In Favor	

Voter	Entity	Segment	P 565 VSL changes	Comments
	Electric Co.			
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Terry L Baker	Platte River Power Authority	3	In Favor	
John C. Collins	Platte River Power Authority	1	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Laurie Williams	Public Service Co. of New Mexico	1	In Favor	
Philip Riley	Public Service	9	In Favor	

Voter	Entity	Segment	P 565 VSL changes	Comments
	Commission of South Carolina			
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
John T. Underhill	Salt River Project	3	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Dennis Sismaet	Seattle City Light	6	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	In Favor	
Bethany Wright	SMUD	5	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Mike Ramirez	SMUD	4	In Favor	
Tim Kelley	SMUD	1	In Favor	

Voter	Entity	Segment	P 565 VSL changes	Comments
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
Jeff Nelson	Springfield Utility Board	3	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
George T. Ballew	Tennessee Valley Authority	5	In Favor	
Brandy A Dunn	WAPA	1	In Favor	
Louise McCarren	WECC	10	In Favor	
Linda Horn	Wisconsin Electric Power Co.	5	In Favor	
James R. Keller	Wisconsin Electric Power Marketing	3	In Favor	
Anthony Jankowski	Wisconsin Energy Corp.	4	In Favor	
Mark Peters	Ameren Services	3	Opposed	
Sam Dwyer	Amerenue	5	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	

Voter	Entity	Segment	P 565 VSL changes	Comments
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Gregory Campoli	NYISO	2	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A. Heimbach	PPL Generation LLC	5	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	
Scott Peterson	San Diego G&E	3	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	

Voter	Entity	Segment	P 565 VSL changes	Comments
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	
Richard McLeon	South Texas Electric Cooperative	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Gregory L Pieper	Xcel Energy, Inc.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	Although the proposed language in R4 addresses the directive, the language is loose and leaves room for interpretation. For example, What constitutes “consider”?; The proposed revised VSLs are too vague as they contain both “consider” ad “appropriate”, both of which are difficult to demonstrate or prove that the responsible entity comply with the intent of the requirement. The change introduces a need to prove that the functional entity “considered” Attachment 1. Either the change should remain and the industry should expect compliance entities to look for such proof; or the proposal should be dropped and allow the functional entities to include only the “applicable elements”. Further, the comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved. We believe that, through this effort, NERC has addressed FERC’s order to “examine whether to clarify this term in the Reliability Standards development process” and that it needs no further clarification at this time. The matter, we are confident, will be fully vetted in the next iteration of this Standard.
Alan Gale	City of Tallahassee	5	Opposed	As written, how does an entity prove that it "considered or addressed" an element that did

Voter	Entity	Segment	P 565 VSL changes	Comments
				not make it into the final version of the plan?
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	comments will be filed via the formal comment form
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Opposed	In the VSLs for R4 the phrase "or addressed" appears however that phrase is not part of the requirement. Maybe "or include" be used in the VSL?
Brad Jones	Luminant Energy	6	Opposed	No opinion
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.
Kim Warren	IESO	2	Opposed	R4 needs to be changed first.
David A. Lapinski	Consumers Energy	3	Opposed	Relative to R4 and the VSLs presented in the draft standard, some entities (particularly those who have entered into JRO's regarding BAL-005, but share R4 responsibilities with other entities) may not have available the ability to apply one or more of the elements in Attachment 1. However, if the entity cannot demonstrate to the satisfaction of the Compliance Monitoring Authority that they have indeed considered these elements, and have, for demonstrable cause, determined that these elements are not "appropriate", it will likely lead to disputes with the Compliance Monitoring Authority when evaluating compliance. "Appropriate" need to be better defined in the context of both R4 and the VSLs.
David Frank Ronk	Consumers Energy	4	Opposed	
James B Lewis	Consumers Energy	5	Opposed	
Richard J Kafka	Potomac Electric Power Co.	1	Opposed	See above
Rex A Roehl	Indeck Energy Services, Inc.	5	Opposed	The VSL levels don't relate to the quality of the emergency plan--they're just checking the boxes. There is no reliability significance to these VSL's.
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	This R4 phrase is vague -includes the phrase "and if appropriate." Who or what basis determines what is or isn't appropriate?
Kirit S. Shah	Ameren Services	1	Opposed	Unless there has been numerous instances of non-compliance of EOP-001, the elements which cannot be determined to have been considered for each of the severity level should be one for Lower, four for Moderate, seven for High and more than seven for Very High (not

Voter	Entity	Segment	P 565 VSL changes	Comments
				labeled). The proposed nubers are consistent with the current VSL if the rounding is down.
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	We agree the changes from paragraph 565 are correctly implemented in the requirement. However, the corresponding changes to the VSLs exceed the scope of the directive and, thus, the scope of the SAR. The Commission did not direct changes to the VSLs from percentage of Attachment 1 elements included to the number of missing Attachment 1 elements compliance.
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P571:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 571	Comments
Allen Mosher	APPA	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric	4	Abstain	

Voter	Entity	Segment	P 571	Comments
	Agency			
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Michael T. Quinn	Oncor Electric Delivery	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Thomas J. Bradish	RRI Energy	5	Abstain	
Trent Carlson	RRI Energy	6	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Liam Noailles	Xcel Energy, Inc.	5	Abstain	

Voter	Entity	Segment	P 571	Comments
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
Jason Shaver	ATC	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	BPA	6	Approve	
Donald S. Watkins	BPA	1	Approve	
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
Brian Conroy	Central Maine Power Co.	1	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	

Voter	Entity	Segment	P 571	Comments
Linda R. Jacobson	City of Farmington	3	Approve	
Danny McDaniel	Cleco Power LLC	1	Approve	
Bryan Y Harper	Cleco Utility Group	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Ajay Garg	Hydro One Networks, Inc.	1	Approve	
Michael D. Penstone	Hydro One Networks, Inc.	3	Approve	
Kim Warren	IESO	2	Approve	

Voter	Entity	Segment	P 571	Comments
Donald Gilbert	JEA	5	Approve	
Charles Locke	KCPL	3	Approve	
Michael Gammon	KCPL	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
John W Delucca	Lee County Electric Cooperative	1	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	

Voter	Entity	Segment	P 571	Comments
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	

Voter	Entity	Segment	P 571	Comments
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Daniel Baerman	San Diego G&E	5	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	

Voter	Entity	Segment	P 571	Comments
Louise McCarren	WECC	10	Approve	
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	

Voter	Entity	Segment	P 571	Comments
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Dan R. Schoenecker	MRO	10	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Bruce Glorvigen	OTP Wholesale Marketing	6	Disapprove	
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	

Voter	Entity	Segment	P 571	Comments
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(a) Section B, R2.1 - unnecessary. Whether the lack of generating capacity was due to a lack of transmission capability or the mitigation is hampered due to lack of transmission capability, it would be dealy with as an emergency due to insufficient generation either way. (b) R2.1 should add "inability of DSM to perform" after insufficient generating capacity (c) R2.1 - lack of transmission is undefined. Is this for n-1, n-2 or for n-7 events? (d) Attachmnet 1 needs to add a new item #16 - Consideration of DSM performance
Greg C Parent	Manitoba Hydro	3	Disapprove	571 - Why not simply the statement to "insufficient generating and or transmission capability" instead of "Including emergencies that arise due to the lack of transmission capability and those whose mitigation plans are hindered by a lack of transmission capability"
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	agrees with the concept but has concerns with the phrase after "and those....". To us the FERC comment of inadequate transmission during the generation emergency is not properly addressed. We suggest changing the edit to: ....Operating emergencies for: 2.1.1 insufficient generation capacity 2.1.2. A lack of transmission capability 2.1.3 A lack of transmission capability while executing a plan responding to a generation emergency
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	Confusing -- mitigation plans are hindered by a lack of transmission capability?
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	Delete the addition of "including emergencies that arise due to or concurrent with

Voter	Entity	Segment	P 571	Comments
				a lack of transmission capability". The proceeding statement is addressed within R2.1 is not required since it is stated in R2.2. The propose modifications do not enhance reliability. NERC can state that the FERC directive was already addressed within R2.2.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE supports MISO's view on this item. Transmission constraints are one of many reasons why a BA may experience a deficiency in generation capacity and does not need not to be emphasized in the requirement. We agree with MISO that the change adds no reliability improvement over the existing language. The direction from FERC was to merely examine, through the SDP, if the suggested change was needed.Its noted that the comment block on the front page of the standard incorrectly references paragraph 582 instead of 571.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Bob Essex	Cowlitz County PUD	5	Approve	However, the tracking section is listing Paragraph 582, not 571.
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Larry Akens	Tennessee Valley Authority	1	Disapprove	I suggest that Requirement 2.1 be re-written as follows: "Develop maintain and implement a set of lans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
George T. Ballew	Tennessee Valley Authority	5	Disapprove	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
Daniel Herring	Detroit Edison Co.	4	Disapprove	Mitigation plans should address scenarios where there are generation emergencies and inadequate transmission capability.
Saurabh Saksena	National Grid	1	Disapprove	National Grid seeks clarification on "and those whose mitigation plans are hindered by a lack of transmission capability". The text seems confusing. Suggest deleting the text to enhance clarity.
Michael F Gildea	Dominion Resources Services	3	Approve	Paragraph 571 - While we agree that the change in paragraph 571 meets FERC directives, we do not necessarily agree that the additional language improves the requirement. We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
Louis S Slade	Dominion Resources, Inc.	6	Approve	

Voter	Entity	Segment	P 571	Comments
Paul Rocha	CenterPoint Energy	1	Disapprove	Paragraph 571 directs the ERO to examine whether the term "insufficient transmission capability" should be clarified. CenterPoint Energy beleives the SDT's attempt at clarification fails to do so and expands R2.1 into R2.2. In the absence of a Commission direction to modify the Standard CenterPoint Energy disapproves the proposed revision.
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 571: The modification to R2.1 is confusing, especially the phrase ï¿½and those whose mitigation plans are hindered by a lack of transmission capabilityï¿½. An operating emergency for insufficient generating capacity can be caused by multiple situations. To clarify the Requirement, Duke Energy suggests R2.1 read; Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity, including emergencies that arise due to a lack of transmission capability.
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Disapprove	R2 is applicable to Transmission Operators and Balancing Authorities and R2.1 states that they shall “develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity”. Currently TOPs and BAs have fulfilled this requirement. The proposed addition of “...including emergencies that arise due to a lack of transmission capacity and those whose mitigation plans are hindered by the lack of transmission capability” does not enhance reliability. A Balancing Authority may not be registered as a Transmission Operator or have the ability to see how they impact the entire transmission system that they are a part of. A Balancing Authority may only have the ability to view some of the transmission system that they are a part of and not how they may affect the system overall. This addition is for a Transmission Operator only, the Balancing Authority should be deleted.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	R2.1 Should be responsibility of BA; R2.2 Should be responsibility of TOP; R2.3 Should be responsibility of both BA and TOP; R2.4 Should be responsibility of TOP per EOP-005
Kevin Koloini	American Municipal Power - Ohio	4	Approve	R2.2 should not apply to the BA. The roles of the TOP and BA are not clear or seem to be confused.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	Revision of R.2.1 introduces ambiguity regarding “and those whose mitigation plans are hindered by a lack of transmission capability”. Is each BA expected to have emergency plans addressing circumstances associated with other entities

Voter	Entity	Segment	P 571	Comments
				mitigation plans which are hindered by a lack of transmission capability? What, or whom, does “those whose” refer to in the new language of this requirement?
Scott Peterson	San Diego G&E	3	Disapprove	The added language is unclear. Is it referring to insufficient generating capacity emergencies that arise due to lack of transmission capability? Isn't that just lack of transmission capacity. Also, is the word "those" referring to emergencies? Isn't the intent of a mitigation plan to remove a hindrance? Isn't that mitigation plan the emergency plan?
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	The change appears to be reasonable.
Alan Gale	City of Tallahassee	5	Disapprove	The direction was to examine if the term needs clarifying. The additional complexity needed to full comply with the standard as written does not improve the BES. Although a gneration capacity emergency can be caused by lack of transmission capability, dictating a rsponse via an operational standard is not going toget lines build overnight. If there is a transmission issue that results in constraints to generation resources, it should be covered in R2.2. It is impractical to write a mitigation plan for every case that could come up. If there is a generation shortage and a transmission constraint, you will be shedding load, which is covered in R2.3.
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	The FERC directive is better served by simply dropping the statement “for insufficient generating capacity”. The requirement would then be to have plans for emergencies.
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Randall McCamish	City of Vero Beach	1	Disapprove	The opportunity should be taken to "fix" R2.1, R2.2 and R2.4. R2.1 requires the TOP to Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity, which is the responsibility fo the BA, not the TOP. And R2.2 requires the BA to develop, maintain and implement a set of plans to mitigate operating emergencies on the transmission system, which is the responsibility of the TOP, not the BA. And, R2.4 conflicts with EOP-005 in that the TOPs develop the restoration plans, not the BA. This can easily be fixed by including applicability in R2.1 through R2.4, i.e., R2.1 Each BA shall develop ..., R2.2 Each TOP shall develop ..., R2.3 Each TOP and BA shall develop ..., and R4 Each TOP shall develop ...
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	

Voter	Entity	Segment	P 571	Comments
Gregory Campoli	NYISO	2	Disapprove	The proposed change to address paragraph 572 is inappropriate. In the FERC-restructured industry the BA is responsible for balancing supply and demand for the purposes of supporting system frequency, the BA does NOT have any responsibility for transmission other than to follow the constrains and directives imposed by its TOPs. This is an issue of fundamentals and the proposal must be rejected. The FERC directive is better served by simply dropping the BA from the requirement and dropping the constraint “for insufficient generating capacity”. The requirement would then be to have plans for emergencies. The fact is that emergency operating plans are focused on the root causes of the reliability issues and not on the generic cause of the issue.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	
Charles H Yeung	Southwest Power Pool	2	Disapprove	The proposed change to address paragraph 572 is inappropriate. In the FERC-restructured industy the BA is responsible for balancing supply and demand for the purposes of supporting system frequency, the BA does NOT have any responsibility for transmission other than to follow the constrains and directives imposed by its TOPs. This is a issue of fundamentals and the proposal must be rejected.
David H. Boguslawski	Northeast Utilities	1	Disapprove	Through this effort NERC has addressed FERC’s order to “examine whether to clarify this term in the Reliability Standards Development Process” and that it needs no further clarification at this time. The matter, we are confident, will be fully vetted in the next iteration of this standard.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	We believe that, through this effort, NERC has addressed FERC’s order to “examine whether to clarify this term in the Reliability Standards development process” and that it needs no further clarification at this time. The matter, we are confident, will be fully vetted in the next iteration of this Standard. The FERC directive is better served by simply dropping the BA from the requirement and dropping the constraint “for insufficient generating capacity”. The requirement would then be to have plans for emergencies. The fact is that emergency operating plans are focused on the root causes of the reliability issues and not on the generic cause of the issue.
David A. Lapinski	Consumers Energy	3	Approve	We recommend changing "insufficient generating capacity" to "insufficient resource capacity"
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	

Voter	Entity	Segment	P 571	Comments
George R. Bartlett	Entergy Corporation	1	Disapprove	We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
Harold Taylor, II	GTC	1	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
Richard J. Mandes	Alabama Power Co.	3	Disapprove	
Stanley M Jaskot	Entergy Corporation	5	Disapprove	
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	We suggest that R2.1 be re-written as follows: "Develop maintain andimplement a set of plans to mitigate operating emergencies that result frominsufficient energy, including the impact of transmission, to meet demand."
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	While we agree that proposed changes appear to address directives in Paragraph 571, we do not understand how these changes further reliability and do not believe they are needed. When the BA is assessing the adequacy of its resources, it considers its whole portfolio which includes it generating fleet, purchases, sales and ability to receive those sales. There are many reasons collectively that a BA may experience an operating emergency due insufficient generator capacity. First and foremost, some event will likely have occurred (i.e. extraordinary record heat wave/cold snap, multiple generator failures, inability to import energy, transmission constraints preventing deliverability). Thus, if transmission constraints are preventing the BA from importing energy, the BA will look to its next available resource which may be shedding load. It makes no sense to single out one of the reasons for experiencing an emergency capacity energy shortage. To satisfy the Commission, we suggest that R2.1 could be modified from using

Voter	Entity	Segment	P 571	Comments
				"insufficient generating capacity" to "insufficient resource adequacy". However, this suggestion should be vetted by a drafting team working specifically on EOP-001. Thus, this directive does not represent low hanging fruit. Modifying sub-requirement R2.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
John K Loftis	Dominion Virginia Power	1	Approve	While we agree that the change in paragraph 571 meets FERC directives, we do not necessarily agree that the additional language improves the requirement. We suggest that R2.1 be re-written as follows: "Develop maintain and implement a set of plans to mitigate operating emergencies that result from insufficient energy, including the impact of transmission, to meet demand."
Mike Garton	Dominion Resources, Inc.	5	Approve	While we agree that this directly addresses the FERC Order 693 Directive, this solution may not be as comprehensive as would be desired to assure reliability. We note that FERC did not require NERC revise the standard to allow the use of non-firm transmission service and believe that further stakeholder vetting of this is superior to the proposed revision to the standard. In the last sentence, "nonfarm" should be "non-firm."
Daniel Prowse	Manitoba Hydro	6	Disapprove	Why not simply the statement to "insufficient generating and or transmission capability" instead of "Including emergencies that arise due to the lack of transmission capability and those whose mitigation plans are hindered by a lack of transmission capability"
Michelle Rheault	Manitoba Hydro	1	Disapprove	Why not simply the statement to "insufficient generating and or transmission capability" instead of "Including emergencies that arise due to the lack of transmission capability and those whose mitigation plans are hindered by a lack of transmission capability"

Voter	Entity	Segment	P 571	Comments
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	Xcel Energy could not find any reference to Para. 571 in EOP-001.
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	

Summary Consideration for changes related to P577:

Some entities expressed concern with the FERC opinion that TLR is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. The response team agrees that the TLR process is one of many tools that can be used in response to real-time situations, but does not believe that the current IRO-006-4 standard precludes its use (except as the sole remedy to such a situation).

Voter	Entity	Segment	P 577	Comments
Allen Mosher	APPA	4	Abstain	
Mel Jensen	APS	5	Abstain	
Robert D Smith	Arizona Public Service Co.	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Timothy VanBlaricom	California ISO	2	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Randall McCamish	City of Vero Beach	1	Abstain	
Danny McDaniel	Cleco Power LLC	1	Abstain	
Bryan Y Harper	Cleco Utility Group	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	

Voter	Entity	Segment	P 577	Comments
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
Larry E Watt	Lakeland Electric	1	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale	5	Abstain	

Voter	Entity	Segment	P 577	Comments
	Electric Co.			
David T. Anderson	Ocala Electric Utility	3	Abstain	
Robert Mattey	Ohio Valley Electric Corp.	1	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Thomas J. Bradish	RRI Energy	5	Abstain	
Trent Carlson	RRI Energy	6	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
Bethany Wright	SMUD	5	Abstain	
James Leigh-Kendall	SMUD	3	Abstain	
Mike Ramirez	SMUD	4	Abstain	
Tim Kelley	SMUD	1	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Jeff Nelson	Springfield Utility Board	3	Abstain	

Voter	Entity	Segment	P 577	Comments
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Louise McCarren	WECC	10	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Kirit S. Shah	Ameren Services	1	Approve	
Mark Peters	Ameren Services	3	Approve	
Sam Dwyer	Amerenue	5	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Jason Shaver	ATC	1	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	BPA	6	Approve	

Voter	Entity	Segment	P 577	Comments
Donald S. Watkins	BPA	1	Approve	
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
Brian Conroy	Central Maine Power Co.	1	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Robert W. Roddy	Dairyland Power Coop.	1	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Michael F Gildea	Dominion Resources	3	Approve	

Voter	Entity	Segment	P 577	Comments
	Services			
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
Robert Smith	Duke Energy	5	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	
Kenneth Dresner	FirstEnergy Solutions	5	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	

Voter	Entity	Segment	P 577	Comments
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Ajay Garg	Hydro One Networks, Inc.	1	Approve	
Michael D. Penstone	Hydro One Networks, Inc.	3	Approve	
Kim Warren	IESO	2	Approve	
Jim D. Cyrulewski	JDRJC Associates	8	Approve	
Donald Gilbert	JEA	5	Approve	
Charles Locke	KCPL	3	Approve	
Michael Gammon	KCPL	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Approve	
Charlie Martin	Louisville Gas and Electric Co.	5	Approve	
Daryn Barker	Louisville Gas and	6	Approve	

Voter	Entity	Segment	P 577	Comments
	Electric Co.			
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
John Bos	Muscatine Power & Water	3	Approve	
Saurabh Saksena	National Grid	1	Approve	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Approve	
David H. Boguslawski	Northeast Utilities	1	Approve	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Gregory Campoli	NYISO	2	Approve	
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	

Voter	Entity	Segment	P 577	Comments
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy	6	Approve	

Voter	Entity	Segment	P 577	Comments
	Resources & Trade LLC			
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Daniel Baerman	San Diego G&E	5	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	

Voter	Entity	Segment	P 577	Comments
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
Charles H Yeung	Southwest Power Pool	2	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
Jonathan Appelbaum	United Illuminating	1	Approve	

Voter	Entity	Segment	P 577	Comments
	Co.			
Brandy A Dunn	WAPA	1	Approve	
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
David F. Lemmons	Xcel Energy, Inc.	6	Approve	
Gregory L Pieper	Xcel Energy, Inc.	1	Approve	
Liam Noailles	Xcel Energy, Inc.	5	Approve	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Greg C Parent	Manitoba Hydro	3	Approve	577 - Although paragraph 577 has been addressed, Manitoba Hydro disagrees with the Commission's view. Response: Thank you for your supportive comment.
Richard J. Mandes	Alabama Power Co.	3	Approve	Addressed in IRO-006. Does something need to be filed with NERC or FERC toexplain that?
Anthony L Wilson	Georgia Power Co.	3	Approve	

Voter	Entity	Segment	P 577	Comments
Gwen S Frazier	Gulf Power Co.	3	Approve	Response: Thank you for your supportive comment. NERC will make a statement to that effect if/when the standard is approved and filed.
Don Horsley	Mississippi Power	3	Approve	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	Although paragraph 577 has been addressed, Manitoba Hydro disagrees with the Commission's view. Response: Thank you for your supportive comment.
Michelle Rheault	Manitoba Hydro	1	Approve	
Walt Gill	Lake Worth Utilities	1	Abstain	do not understand why this is being balloted since there is no change Response: The team is attempting to confirm that entities agree no change is needed.
Terri Pyle	Oklahoma Municipal Power Authority	4	Abstain	No changes made Response: No response required.
Alan Gale	City of Tallahassee	5	Approve	The change to IRO adequately addresses the paragraph 577 action. Response: Thank you for your supportive comment
James V. Petrella	Atlantic City Electric Co.	3	Abstain	The directive has already been met. Response: Thank you for your supportive comment
Richard J Kafka	Potomac Electric Power Co.	1	Abstain	
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	TLR remains one additional component to solving a violation and should not be discounted as one tool used in conjunction with other emergency steps to resolve a violation. Response: The SDT does not disagree with this statement, but believes IRO-006 allows TLR to be used as such a tool.
Jason L Marshall	Midwest ISO, Inc.	2	Approve	We agree that the directives from paragraph 577 have already been addressed in IRO-006-4. Response: Thank you for your supportive comment.
Kathleen Goodman	ISO New England, Inc.	2	Abstain	We agree with NERC that this directive has already been addressed in IRO-006-4 but do not know how to vote to indicate such agreement.

Voter	Entity	Segment	P 577	Comments
				Response: Thank you for your supportive comment.
Frank Gaffney	Florida Municipal Power Agency	4	Abstain	We do not understand why this is being balloted since there is no change Response: The team is attempting to confirm that entities agree no change is needed.
Guy Andrews	Georgia System Operations Corporation	4	Approve	While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Harold Taylor, II	GTC	1	Approve	While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.
Gregg R Griffin	City of Green Cove Springs	3	Abstain	why on ballot ... no changes proposed Response: The team is attempting to confirm that entities agree no change is needed.
Douglas E. Hils	Duke Energy Carolina	1	Approve	With this vote we are not agreeing to any changes, we are agreeing that the directive in Paragraph 577 have already been addressed in IRO-006-4. Response: Thank you for your supportive comment.

Summary Consideration for changes related to P582:

Several entities suggested that Measure M5 was written in a confusing and potentially unreliable fashion. The Response Team agreed, and modified the Measure to read as follows:

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes.

Some entities expressed concern with the phrase, “when required and appropriate.” The Response Team pointed out that this is approved language form the existing standard, and intended to ensure that entities take the appropriate action that is required given current conditions.

Voter	Entity	Segment	P 582	Comments
Allen Mosher	APPA	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Danny McDaniel	Cleco Power LLC	1	Abstain	
Bryan Y Harper	Cleco Utility Group	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de	ConEd of NY	1	Abstain	

Voter	Entity	Segment	P 582	Comments
Graffenried				
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
Donald Gilbert	JEA	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	

Voter	Entity	Segment	P 582	Comments
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Robert Mattey	Ohio Valley Electric Corp.	1	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Thomas J. Bradish	RRI Energy	5	Abstain	
Trent Carlson	RRI Energy	6	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L.	Southwest	1	Abstain	

Voter	Entity	Segment	P 582	Comments
Jones	Transmission Cooperative, Inc.			
Jeff Nelson	Springfield Utility Board	3	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Kirit S. Shah	Ameren Services	1	Approve	
Mark Peters	Ameren Services	3	Approve	
Sam Dwyer	Amerenue	5	Approve	

Voter	Entity	Segment	P 582	Comments
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Brenda S. Anderson	BPA	6	Approve	
Donald S. Watkins	BPA	1	Approve	
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	

Voter	Entity	Segment	P 582	Comments
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Robert Smith	Duke Energy	5	Approve	
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	

Voter	Entity	Segment	P 582	Comments
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Charles Locke	KCPL	3	Approve	
Michael Gammon	KCPL	1	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Joseph G.	Madison Gas and	4	Approve	

Voter	Entity	Segment	P 582	Comments
DePoorter	Electric Co.			
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
John Bos	Muscatine Power & Water	3	Approve	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power	4	Approve	

Voter	Entity	Segment	P 582	Comments
	Authority			
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Tim	PowerSouth Energy	5	Approve	

Voter	Entity	Segment	P 582	Comments
Hattaway	Cooperative			
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	

Voter	Entity	Segment	P 582	Comments
Robert Kondziolka	Salt River Project	1	Approve	
Daniel Baerman	San Diego G&E	5	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
RJames	Tampa Electric Co.	5	Approve	

Voter	Entity	Segment	P 582	Comments
Rocha				
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Jim D.	JDRJC Associates	8	Disapprove	

Voter	Entity	Segment	P 582	Comments
Cyrulewski				
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	"if appropriate" terminology in R2 leaves room for interpretation and should be removed or defined. Response: This language was not modified from the original standard, only moved to make the requirement more easily understood.
Kenneth Dresner	FirstEnergy Solutions	5	Approve	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments." Response: Please see response to Doug Hohlbaugh.

Voter	Entity	Segment	P 582	Comments
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form Response: Please see the appropriate "Consideration of Comments" for the response.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	Hopefully the intent was that the subrequirements were not to be executed in order, to eliminate confusion, it is suggested that the subrequirements dealing with reducing firm load should always be listed last. Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.
Larry Akens	Tennessee Valley Authority	1	Disapprove	
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	While we do not believe that the sub-requirments are intended to be executed in order, we suggest that R6.8 should be ordered prior to reducing load. Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.
Saurabh Saksena	National Grid	1	Disapprove	In Order 693, the Commission correctly determined that "With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO's Reliability Standards development process to ensure that their opinions are considered. Such changes are appropriately considered "low hanging fruit" and should be will be fully vetted in the next iteration of this standard. Response: Thank you for your supportive comment.
Michael F Gildea	Dominion Resources Services	3	Approve	Paragraph 582 - While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.
Louis S Slade	Dominion Resources, Inc.	6	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
John D. Martinsen	Public Utility District No. 1 of	4	Approve	R2 includes the phrase "and as appropriate." Who or what basis determines what is or isn't appropriate? We agree with the concept that not all actions included in the plan need to be

Voter	Entity	Segment	P 582	Comments
	Snohomish County			implemented for every event, but the phrase is vague. Response: This language was not modified from the original standard, only moved to make the requirement more easily understood.
Eric Egge	Black Hills Corp	1	Approve	R2 includes the phrase “and as appropriate.” Who or what determines what is or isn’t appropriate? We agree with the concept that not all actions include in the plan need to be implemented for every event, but this phrase is vague. Response: This language was not modified from the original standard, only moved to make the requirement more easily understood.
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Louise McCarren	WECC	10	Approve	R2 includes the phrase “and as appropriate.” Who or what determines what is or isn’t appropriate? We agree with the concept that not all actions included in the plan need to be implemented for every event, but this phrase is vague. Clarifying language should be added indicating that the applicable entity is the appropriate party to determine which actions described in its capacity and energy emergency plan are "apropriate." Response: This language was not modified from the original standard, only moved to make the requirement more easily understood.
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	R2- Not sure words clarify anything. What if two actions are required under the plan for a situation but they only took one. Should it not be something like “ ... shall take actions required and appropriate for an emergency situation as described in its capacity and emergency plan or substitute alternative actions as appropriate to the current situation based on operator discretion to reduce risks to...”If this is changed, then M2 needs to change to reflect any changes. Response: The original language from the requirement, “when required and as appropriate,” is intended to ensure entities take the appropriate action that is required.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	R2- Not sure words clarify anything. What if two actions are required underthe plan for a situation but they only took one. Should it not be something like “... shall take actions required and appropriate for an emergency situation asdescribed in its capacity and emergency plan or substitute alternative
Anthony L	Georgia Power Co.	3	Disapprove	

Voter	Entity	Segment	P 582	Comments
Wilson				actions asappropriate to the current situation based on operator discretion to reduce risksto...”If this is changed, then M2 needs to change to reflect any changes. Response: The original language form the requirement, “when required and as appropriate,” is intended to ensure entities take the appropriate action that is required.
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Linda R. Jacobson	City of Farmington	3	Approve	R4 includes the phrase “and if appropriate.” Who or what determines what is or isn’t appropriate? Response: This language was not modified from the original standard, only moved to make the requirement more easily understood.
Charles H Yeung	Southwest Power Pool	2	Disapprove	The change to R2 does nothing to clarify what it means to “reduce risk” or what “as required” means (does this mean if something bad happened that the entiy by definition is non-compliant since it obviously didn’t do “what was required to address the problem”?). How is risk meaured? Measure 2 requires the entity to show that its acts were in “conformance” with its plans. Does that preclude a system operator from varying with a particular step in its own emergency plans? Response: This language was not modified from the original standard.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	The changes to R2 are unnecessary and only state the obvious. A capacity and emergency plan must identify when it is appropriate and required to take actions. Adding the clause to R2 provides no reliability benefit. Furthermore, the directive only requires the ERO to address ISO-NE concern, not to necessarily modify the standard. The concern should be addressed by a simple explanation that if their plan allows them to skip steps, they have met the requirement by having a plan and implementation of their plan allows them to implement only what is necessary. We disagree with adding Measures through this standards action. FERC was clear in paragraph 616 from Order 693 that determination of the need for a requirement to have a measure was at the ERO’s discretion. Thus, measures do not appear to be a major concern of FERC and making changes to measures will not demonstrate a commitment to complete directives from Order 693. Thus, there is no need to make changes to measures through an expedited process.Measurement 5 is fundamentally incorrect. R5 is intended to limit a BA’s assistance on the Interconnection to the frequency response obligation established by the frequency bias settings for a few minutes (up to 15) after the loss of a resource. Measurement 5 reads to limit all Interconnection assistance and could be construed as limiting the import schedules. The wording should be made parallel to the requirement. We suggest: “The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that

Voter	Entity	Segment	P 582	Comments
				supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)" Response: The directive to address the stated ISONE concern indicates that the answer was not obvious; hence the modification. The Response Team believes that adding measures improves the clarity of the standard. Additionally, the Response Team has modified M5 as suggested to address your concern.
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	The changes to R2 largely seem unnecessary, however, FE approves based on the change does not seem to harm reliability or reduce clarity. Response: Thank you for your supporting comment.
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	The ISO-NE comment to the NOPR was valid for a prior version of the standards. It is no longer necessary. Response: It is not clear that FERC believes this item has been addressed in previous modifications. The Response Team believes that this change clearly demonstrates compliance with the FERC directive.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Gregory Campoli	NYISO	2	Disapprove	The proposed changes do not address the underlying problem with the entire standard which is how to write emergency standards related to system control. What is an emergency state for a BA? If the BA must balance supply and demand both instantaneously and "on average" then when does an emergency begin for the BA? In Balancing, one could argue the only issue is does the BA have enough supply and if not then shed load. Too much supply is handled by exercising its authority over GOPs. Such fundamental issues must be discussed before expediting minor adjustments. The change to R2 does nothing to clarify what it means to "reduce risk" or what "as required" means (does this mean if something bad happened that the entity by definition is non-compliant since it obviously didn't do "what was required to address the problem"?). How is risk measured? Measure 2 requires the entity to show that its acts were in "conformance" with its plans. Does that preclude a system operator from varying with a particular step in its own emergency plans? Does approval of the proposed changes constitute an approval of EOP-002? This is important because: R4, R5, R6 are examples of requirements that need a major rewriting, or at least major discussion. R4 imposes an immeasurable "anticipation" step. Without being able to measure "anticipation" this requirement has no meaning. An entity that did not "anticipate" the emergency cannot be held non-compliant with R4! R5 treats frequency control as if it were a fine-tuning process. Moreover, as written R5 places a ceiling on how much real power may be exchanged over and above its scheduled interchange. Since ACE already introduces a bias for the frequency, it would seem that "any" non-zero ACE would represent

Voter	Entity	Segment	P 582	Comments
				non-compliance to this requirement. The standard was written with regard to correcting frequency - but in the mandatory compliance world the "intentions" of the entity is not measureable so any error could be assumed to be used to assist frequency. R6 is unclear. What constitutes "immediately"? If all remedies are optional, then no remedy is required, making compliance a moot point. The proposed M5 does not correspond to the condition stipulated in R5. The proposed Measure appears to expand the scope of the Requirement in regard of utilization unilateral generation adjustment. We suggest the latter part in M5 to be reworded as "...and that in its attempts to return Interconnection frequency to normal, it did not unilaterally adjust generation beyond that supplied through frequency bias action and Interchange Schedule changes." Response: The changes made to the standard are specific attempts to address Commission directives. To the extent the industry believe it appropriate to redraft the entire standard, we encourage such efforts. We understand that there are concerns that the standard should be rewritten, and there are efforts underway to do just that. However, in the immediate future, the Response Team believes that the proposed changes improve the quality of the standard. Additionally, the Response Team has modified M5 as suggested to address your concern.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	The proposed changes do not address the underlying problem with the entire standard which is how to write emergency standards related to system control. What is an emergency state for a BA? If the BA must balance supply and demand both instantaneously and "on average" then when does an emergency begin for the BA? In Balancing, one could argue the only issue is does the BA have enough supply and if not then shed load. Too much supply is handled by exercising its authority over GOPs. Such fundamental issues must be discussed before expediting minor adjustments. The change to R2 does nothing to clarify what it means to "reduce risk" or what "as required" means (does this mean if something bad happened that the entity by definition is non-compliant since it obviously didn't do "what was required to address the problem"?). How is risk measured? Measure 2 requires the entity to show that its acts were in "conformance" with its plans. Does that preclude a system operator from varying with a particular step in its own emergency plans? Does approval of the proposed changes constitute an approval of EOP-002? This is important because: R4, R5, R6 are examples of requirements that need a major rewriting, or at least major discussion. R4 imposes an immeasurable "anticipation" step. Without being able to measure "anticipation" this requirement has no meaning. An entity that did not "anticipate" the emergency cannot be held non-compliant with R4! R5 treats frequency control as if it were a fine-tuning process. Moreover, as written R5 places a ceiling on how much real power may be exchanged over and above its scheduled interchange. Since ACE

Voter	Entity	Segment	P 582	Comments
				already introduces a bias for the frequency, it would seem that "any" non-zero ACE would represent non-compliance to this requirement. The standard was written with regard to correcting frequency - but in the mandatory compliance world the "intentions" of the entity is not measureable so any error could be assumed to be used to assist frequency. R6 is unclear. What constitutes "immediately"? If all remedies are optional, then no remedy is required, making compliance a moot point. The proposed M5 does not correspond to the condition stipulated in R5. The proposed Measure appears to expand the scope of the Requirement in regard of utilization unilateral generation adjustment. We suggest the latter part in M5 to be reworded as "...and that in its attempts to return Interconnection frequency to normal, it did not unilaterally adjust generation beyond that supplied through frequency bias action and Interchange Schedule changes." Response: The changes made to the standard are specific attempts to address Commission directives. To the extent the industry believe it appropriate to redraft the entire standard, we encourage such efforts. We understand that there are concerns that the standard should be rewritten, and there are efforts underway to do just that. However, in the immediate future, the Response Team believes that the proposed changes improve the quality of the standard. Additionally, the Response Team has modified M5 as suggested to address your concern.
Kathleen Goodman	ISO New England, Inc.	2	Abstain	This comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved.In Order 693, the Commission correctly determined that "With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO's Reliability Standards development process to ensure that their opinions are considered." We do not believe such changes are appropriately considered "low hanging fruit" and should be will be fully vetted in the next iteration of this Standard. Response: It is not clear that FERC believes this item has been addressed in previous modifications. The Response Team believes that this change clearly demonstrates compliance with the FERC directive.

Voter	Entity	Segment	P 582	Comments
				The Response Team also believes that adding the measures improves the overall clarity of the standard.
David H. Boguslawski	Northeast Utilities	1	Disapprove	This comment offered by ISO-NE in the NOPR on the version 0 standards was based on a standard that was two versions prior. ISO-NE, as part of this effort, has reviewed their comment and the existing version of EOP-001 and agree that the comment is no longer valid, and, therefore, the FERC issue has been appropriately resolved. Response: It is not clear that FERC believes this item has been addressed in previous modifications. The Response Team believes that this change clearly demonstrates compliance with the FERC directive.
Kim Warren	IESO	2	Approve	We do not agree with the proposed M5 since the second part does not correspond to the condition stipulated in R5. The proposed Measure appears to expand the scope of the Requirement in regard of utilization unilateral generation adjustment. We suggest the latter part in M5 to be reworded as "...and that in its attempts to return Interconnection frequency to normal, it did not unilaterally adjust generation beyond that supplied through frequency bias action and Interchange Schedule changes." The Response Team has modified M5 as suggested to address your concern.
Mike Garton	Dominion Resources, Inc.	5	Approve	While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last. Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Harold Taylor, II	GTC	1	Approve	
George R. Bartlett	Entergy Corporation	1	Disapprove	While we do not believe that the sub-requirements of R6 are intended to be executed in order, we suggest that R6.8 should be ordered prior to reducing load. Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	

Voter	Entity	Segment	P 582	Comments
John Tolo	Tucson Electric Power Co.	1	Approve	R4 includes the phrase “and if appropriate.” Who or what determines what is or isn’t appropriate? Response: This language was not modified from the original standard, only moved to make the requirement more easily understood.

Summary Consideration for changes related to P573:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 573	Comments
Allen Mosher	APPA	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Timothy VanBlaricom	California ISO	2	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	

Voter	Entity	Segment	P 573	Comments
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	

Voter	Entity	Segment	P 573	Comments
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Robert Mattey	Ohio Valley Electric Corp.	1	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Thomas J. Bradish	RRI Energy	5	Abstain	
Trent Carlson	RRI Energy	6	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer	U.S. Bureau of	5	Abstain	

Voter	Entity	Segment	P 573	Comments
P.E.	Reclamation			
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S.	BPA	6	Approve	

Voter	Entity	Segment	P 573	Comments
Anderson				
Donald S. Watkins	BPA	1	Approve	
Francis J. Halpin	BPA	5	Approve	
Rebecca Berdahl	BPA	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County	5	Approve	

Voter	Entity	Segment	P 573	Comments
	PUD			
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power	3	Approve	

Voter	Entity	Segment	P 573	Comments
	Corporation			
Thomas E Washburn	FMPP	6	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Kim Warren	IESO	2	Approve	
Donald Gilbert	JEA	5	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	

Voter	Entity	Segment	P 573	Comments
David T. Anderson	Ocala Electric Utility	3	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J	Potomac Electric	1	Approve	

Voter	Entity	Segment	P 573	Comments
Kafka	Power Co.			
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of	3	Approve	

Voter	Entity	Segment	P 573	Comments
	Grant County			
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Daniel Baerman	San Diego G&E	5	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard	South Carolina	5	Approve	

Voter	Entity	Segment	P 573	Comments
Jones	Electric & Gas Co.			
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	WAPA	1	Approve	
Louise McCarren	WECC	10	Approve	
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	

Voter	Entity	Segment	P 573	Comments
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	

Voter	Entity	Segment	P 573	Comments
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Dan R. Schoenecker	MRO	10	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Bruce Glorvigen	OTP Wholesale Marketing	6	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F.	Xcel Energy, Inc.	6	Disapprove	

Voter	Entity	Segment	P 573	Comments
Lemmons				
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(a) R 6.8 - Unknown technologies are not "technically feasible". Delete this sub requirement. (b) In Attachment 1, Alert 1 - does "All Available Resources" include DSM? If resources are comparable, why woudn't it be?
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	As a general matter, we oppose inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement. We believe this results in a "HOW" to meet a requirement instead of "WHAT" to meet the requirements and, have, in the past opposed such specifications within the Standards. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Daniel Herring	Detroit Edison Co.	4	Disapprove	Deployment of DSM verbiage should either be "available" or "request all".
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	DSM Resource(s) should be defined and included in R6
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE believes the topic of DSM requires further technical consideration. See our comment in regards to paragraph 330.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Saurabh Saksena	National Grid	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to

Voter	Entity	Segment	P 573	Comments
				enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. In Order 693, the Commission correctly determined that "With regard to the comments of Nevada Companies, Progress and others, we believe that the ERO should have flexibility in initially developing appropriate Measures and Levels of Non-Compliance. For example, the ERO in the first instance should determine whether a Measure is necessary for every Requirement of a particular Reliability Standard, or whether every Reliability Standard must have the same number of Levels of Non-Compliance. Entities interested in developing meaningful Measures and Levels of Non-Compliance should, we find, participate in the ERO's Reliability Standards development process to ensure that their opinions are considered. Such changes are appropriately considered "low hanging fruit" and should be will be fully vetted in the next iteration of this standard.
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	Not sure why R6.3 is needed. Demand Side Management could be put in the list for R6.7 and be less controversial. As stated earlier, although FERC states that "demand response covers considerably more resources than interruptible load" it is not clear to any reader what that might be. Expect confusion to cause problems with proposed changes being low hanging fruit.Note: Demand-side management is explicitly listed in Alert 2 in current Attachment 1
Richard J. Mandes	Alabama Power Co.	3	Disapprove	
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 573: Duke Energy is not in a position to deploy all Demand Side Management (DSM) options. For certain DSM options, Duke Energy may request the use of DSM but the customer has the ultimate call whether to deploy or not. For this reason Duke Energy suggests deleting the word "all" from R6.3. Would R6.8 require Duke Energy to put alternative technologies on our system? If we do not own alternative technologies, how do we comply with this Requirement?We are OK with the addition of the new Measures.

Voter	Entity	Segment	P 573	Comments
Doug Bantam	LES	1	Disapprove	R6.3 and R6.8 should be replaced by using Direct Control Load Management. DCLM as defined here does not include Interruptible Demand.
Dennis Florom	LES	5	Disapprove	
Eric Ruskamp	LES	6	Disapprove	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Disapprove	R6.3 and R6.8 should be replaced by using Direct Control Load Management (DLCM). As described in the NERC Glossary of terms: DLCM is “Demand-Side Management (DSM) that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand”. Per NERC Glossary of terms, Demand Side Management is undertaken by the Load Serving Entity or its customers, whereas DCLM is under the direct control of system operators. NERC’s Glossary of terms goes on to define a system operator as “an individual at a control center (BA, TOP, GOP, RC) whose responsibility it is to monitor and control that electric system in real time”. DCLM should be used in place of DSM since it has more applicable entities per NERC definition.
Danny McDaniel	Cleco Power LLC	1	Disapprove	Requirement R6.8 is too broad and does not define "any available alternative technologies". Also, Cleco is not clear on the intent of "Deploying" in requirement R6.3 or R6.8
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	See our comments above about inclusion of specific technologies.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Jeff Nelson	Springfield Utility Board	3	Disapprove	See SUB's comment form
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	Some DSM programs allow the end use customer the final option of deployment or the customer may have an option to over-ride and DSM.
Charles Locke	KCPL	3	Disapprove	Sub-requirement R6.8 is ambiguous and subject to interpretation and recommend removal. The other sub-requirements R6.1 through R6.7 are sufficiently comprehensive as available recovery actions and the removal of R6.8 does not compromise the response to the directive language to be addressed. In addition, although not one of the changes submitted, requirement R6 should be considered for a modification to reflect language that targets maintaining a balance of energy
Michael Gammon	KCPL	1	Disapprove	

Voter	Entity	Segment	P 573	Comments
				resources and energy obligations in real time. The current references to Control Performance and Disturbance Control Standards over longer operating ranges does not accurately reflect the need for immediate operator actions. Recommend modifying the language to “cannot maintain ACE within Lsub10 limits, then . . .”.
Gregory Campoli	NYISO	2	Disapprove	The proposed changes do not change the requirement. Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to be a tool for control. The SAR requestor proposes to meet this directive by inserting DSM into a list. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	The proposed changes do not change the requirement. Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to be a tool for control. The SAR requestor proposes to meet this directive by inserting DSM into a list. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Charles H Yeung	Southwest Power Pool	2	Disapprove	The proposed changes do not change the requirement. Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionarty list. The FERC mandate is that DSM explicitly be allowed to be a tool for control. The SAR requestor proposes to meet this directive by inserting DSM into a list. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used.
Terry	MidAmerican	1	Disapprove	To address paragraph 573 adjust the proposed wording in R6 to read “all available” with “all applicable”. For FERC Paragraph 573 and EOP-002, eliminate R6.8 as unnecessary. FERC’s directive is

Voter	Entity	Segment	P 573	Comments
Harbour	Energy Co.			adequately addressed in R6.3. Blanket statements are vague and cannot be clearly audited.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We do not believe the directive in paragraph 573 represents low hanging fruit. We are supportive of using DSM but we believe a drafting team needs to carefully work through addressing this directive to avoid unintended consequences. Based on the proposed definition of DSM in BAL-002, it is not clear if interruptible load is distinctly differently or one of the various types of DSM. If it is one of the various types of DSM, then R6.4 is duplicative of R6.3. Further changes may be required to the standard to address the directive as well. For example, why would R4 not include notifying the "end-use customers, Load-Serving Entities, or their agents or representatives" to anticipate the need to call upon DSM?Adding sub-requirements R6.3 and R6.8 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Guy Andrews	Georgia System Operations Corporation	4	Approve	While we do not believe that the sub-requirements are intended to be executed in order, we suggest that that the sub-requirement that includes reducing load should always be last.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Harold Taylor, II	GTC	1	Approve	

Voter	Entity	Segment	P 573 VSL changes	Comments
Raj Rana	AEP	3	In Favor	
Edward P. Cox	AEP Marketing	6	In Favor	
Brock Ondayko	AEP Service Corp.	5	In Favor	
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	In Favor	
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Donald S. Watkins	BPA	1	In Favor	
Francis J. Halpin	BPA	5	In Favor	
Rebecca Berdahl	BPA	3	In Favor	
John Yale	Chelan County Public Utility	5	In Favor	

Voter	Entity	Segment	P 573 VSL changes	Comments
	District #1			
Linda R. Jacobson	City of Farmington	3	In Favor	
Gregg R Griffin	City of Green Cove Springs	3	In Favor	
Alan Gale	City of Tallahassee	5	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
David A. Lapinski	Consumers Energy	3	In Favor	
David Frank Ronk	Consumers Energy	4	In Favor	
James B Lewis	Consumers Energy	5	In Favor	
Russell A Noble	Cowlitz County PUD	3	In Favor	
Daniel Herring	Detroit Edison Co.	4	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia	1	In Favor	

Voter	Entity	Segment	P 573 VSL changes	Comments
	Power			
George R. Bartlett	Entergy Corporation	1	In Favor	
Stanley M Jaskot	Entergy Corporation	5	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Guy Andrews	Georgia System Operations Corporation	4	In Favor	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	In Favor	
Harold Taylor, II	GTC	1	In Favor	
Kim Warren	IESO	2	In Favor	
Donald Gilbert	JEA	5	In Favor	

Voter	Entity	Segment	P 573 VSL changes	Comments
Walt Gill	Lake Worth Utilities	1	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Steven M. Jackson	MEAG	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark	PacifiCorp	1	In Favor	

Voter	Entity	Segment	P 573 VSL changes	Comments
Sampson				
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Terry L Baker	Platte River Power Authority	3	In Favor	
John C. Collins	Platte River Power Authority	1	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Laurie Williams	Public Service Co. of New Mexico	1	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of	4	In Favor	

Voter	Entity	Segment	P 573 VSL changes	Comments
	Snohomish County			
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
John T. Underhill	Salt River Project	3	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Terry L. Blackwell	Santee Cooper	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Dennis Sismaet	Seattle City Light	6	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	In Favor	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	In Favor	
Bethany Wright	SMUD	5	In Favor	
James Leigh-	SMUD	3	In Favor	

Voter	Entity	Segment	P 573 VSL changes	Comments
Kendall				
Mike Ramirez	SMUD	4	In Favor	
Tim Kelley	SMUD	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
Steve McElhaney	South Mississippi Electric Power Association	4	In Favor	
Jerry W Johnson	South Mississippi Electric Power Association	5	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
George T. Ballew	Tennessee Valley Authority	5	In Favor	
Brandy A Dunn	WAPA	1	In Favor	
Louise McCarren	WECC	10	In Favor	
Richard J. Mandes	Alabama Power Co.	3	Opposed	

Voter	Entity	Segment	P 573 VSL changes	Comments
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Robert Smith	Duke Energy	5	Opposed	
Walter Yeager	Duke Energy Carolina	6	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	

Voter	Entity	Segment	P 573 VSL changes	Comments
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
John Bos	Muscatine Power & Water	3	Opposed	
Saurabh Saksena	National Grid	1	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
Gregory Campoli	NYISO	2	Opposed	
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Bruce Glorvigen	OTP Wholesale Marketing	6	Opposed	

Voter	Entity	Segment	P 573 VSL changes	Comments
Tim Hattaway	PowerSouth Energy Cooperative	5	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A. Heimbach	PPL Generation LLC	5	Opposed	
Richard McLeon	South Texas Electric Cooperative	1	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	Because of our comment to R6.3 we would vote No on the VSL changes.
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 573 in their current format, we cannot support the changes to the VSLs.
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Anthony Jankowski	Wisconsin Energy Corp.	4	Opposed	High VSL:The Balancing Authority was notable to comply with the ControlPerformance and DisturbanceControl Standards and implemented all but one (1) ofthe eight (8) applicable sub-requirements R6.1, R6.2,R6.3, R6.4, R6.5, R6.6, R6.7, orR6.8.Severe VSL:The Balancing Authority was

Voter	Entity	Segment	P 573 VSL changes	Comments
				notable to comply with the ControlPerformance and DisturbanceControl Standards and implemented all but two (2) or moreof the eight (8) applicable sub-requirementsR6.1, R6.2, R6.3, R6.4, R6.5, R6.6,R6.7, or R6.8.The word “immediately” is struck because it seems unlikely that any BA could implement all the requirements simultaneously. Is a 30 minute time frame to implement all applicable remedies be more reasonable (similar to an IROL)?
Brad Jones	Luminant Energy	6	Opposed	No opinion
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.
Michael Gammon	KCPL	1	Opposed	Recommend removal of R6.8 from the VSL. Also consider modifying the VSL to replace CPS and DCS with ACE exceeding Lsub10 limits.
Charles Locke	KCPL	3	Opposed	
Jeff Nelson	Springfield Utility Board	3	Opposed	See SUB's comment form
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	The proposed changes do not change the requirement. Inserting lists into requirements creates the risk of the list being used by future compliance entities as an exclusionary rather than an inclusionary list. The FERC mandate is that DSM explicitly be allowed to be a tool for control. The SAR requestor proposes to meet this directive by inserting DSM into a list. The requestor does not consider an equally effective alternative of making this explicit statement elsewhere than the requirement, e.g. in the compliance section. Such alternatives are allowed by FERC but needs to be considered by the Industry as to which other alternatives can be used. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Linda Horn	Wisconsin Electric Power Co.	5	Opposed	The wording in the Violation Severity Levels is not clear to me. Suggest changing the wording to something like: High VSL:The Balancing Authority was notable to comply with the ControlPerformance and DisturbanceControl Standards and failed toimmediately implemented all but one (1) ofthe eight (8) applicable sub-requirements R6.1, R6.2,R6.3, R6.4, R6.5, R6.6, R6.7, orR6.8.Severe VSL:The Balancing Authority was notable to comply with the ControlPerformance and DisturbanceControl Standards and failed toimmediately implemented all but two (2) or more thanone (1) of the eight (8) applicable sub-requirementsR6.1, R6.2, R6.3, R6.4, R6.5, R6.6,R6.7, or R6.8.ORThe Balancing Authority was notable to comply with the ControlPerformance and DisturbanceControl Standards and did
James R. Keller	Wisconsin Electric Power Marketing	3	Opposed	

Voter	Entity	Segment	P 573 VSL changes	Comments
				notimmediately implement anyremedies.The word “immediately” is struck because it seems unlikely that any BA could implement all the requirements simultaneously. Is a 30 minute time frame to implement all applicable remedies be more reasonable (similar to an IROL)?
Rex A Roehl	Indeck Energy Services, Inc.	5	Opposed	The working of these VSL's is that failure to implement one (or any), or is it all, of the elements is a High VSL and failure to implement more than one (or some), but less than all of the elements is a Severe VSL. Not all elements are equivalent in impact based on the situation. Not implementing one with small impact is very different from not implementing one with large impact. If implementing one was sufficient, but implementing two different ones that aren't sufficient isn't compliance. The reliability significance needs to be measured or the VSL is meaningless.
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P601:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 601	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	APPA	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	

Voter	Entity	Segment	P 601	Comments
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Kenneth Simmons	Gainesville Regional Utilities	3	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Donald Gilbert	JEA	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	

Voter	Entity	Segment	P 601	Comments
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R.	City of Farmington	3	Approve	

Voter	Entity	Segment	P 601	Comments
Jacobson				
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	

Voter	Entity	Segment	P 601	Comments
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Saurabh Saksena	National Grid	1	Approve	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Approve	
Mark A. Heimbach	PPL Generation LLC	5	Approve	
James Eckelkamp	Progress Energy	6	Approve	

Voter	Entity	Segment	P 601	Comments
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	

Voter	Entity	Segment	P 601	Comments
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Brandy A	WAPA	1	Approve	

Voter	Entity	Segment	P 601	Comments
Dunn				
Louise McCarren	WECC	10	Approve	
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Francis J. Halpin	BPA	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	
Nickesha P Carrol	ConEd of NY	6	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Daniel Herring	Detroit Edison Co.	4	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter	Duke Energy	6	Disapprove	

Voter	Entity	Segment	P 601	Comments
Yeager	Carolina			
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Dan R. Schoenecker	MRO	10	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T.	Ocala Electric	3	Disapprove	

Voter	Entity	Segment	P 601	Comments
Anderson	Utility			
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Bruce Glorvigen	OTP Wholesale Marketing	6	Disapprove	
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
John Apperson	PacifiCorp	3	Disapprove	
Mark Sampson	PacifiCorp	1	Disapprove	
Sandra L. Shaffer	PacifiCorp	5	Disapprove	
Greg Lange	Public Utility District No. 2 of Grant County	3	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W	South Mississippi	5	Disapprove	

Voter	Entity	Segment	P 601	Comments
Johnson	Electric Power Association			
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(a) R3.4- This standard does not apply to Generator Owner, but the requirement is to coordinate with them. What reason would GO have to comply if there are no consequences of non-compliance. It will be difficult to coordinate with a GO having no measure for compliance (b) On the other hand, R3 does not require to coordinate with LSE and DP, but R9 does. Again the standard does not apply to LSE or DP and for that reason would be difficult to coordinate for R9. (c) R8 - what does "test through simulation " mean? Does that mean table top drills, actual signals but not implemented, load flow and dynamic model simulations? This requirement is vauge.
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. These new provisions are in conflict with the proposed PRC-006 NERC standard, and should be addressed in this forum. 2. There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9.3. What are personnel deployment drills? Are these applicable to automatic load shedding? 4. Requirement R9 is not in the directive; and is outside the scope of the directive.

Voter	Entity	Segment	P 601	Comments
Mike Garton	Dominion Resources, Inc.	5	Disapprove	Although we agree that the changes meet the FERC Directive, we suggest the this version is premature given that Project 2007-01 (Underfrequency Load Shedding) contains requirements related to under-frequency load shedding, already contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft. We suggest the SDT take no action on this revision pending the outcome of balloting in Project 2007-01. Both requirements are ambiguous. They call for the testing of plans - not testing of the actual capability of shedding load. The best I can figure out is that R8 calls for some level of testing that the TOP or BA can do on their own, while R9 calls for a full-blown drill involving all applicable parties. The “simulation” required for R8 probably refers to pretending to coordinate with other parties as opposed to using a training simulator or actually operating “test” relays that aren’t wired to breaker trip circuits. I’m thinking that if you did R9 annually instead of every two years, you would have R8 covered. If the PJM Emergency Procedures Drills would suffice for R9, then we do those twice per year. It is difficult to interpret the actual intent of these two requirements. They both need to be clarified.
George R. Bartlett	Entergy Corporation	1	Disapprove	Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	
Paul Rocha	CenterPoint Energy	1	Disapprove	CenterPoint Energy notes that in paragraph 601 the Commission directs the ERO to consider the comments regarding the expansion of coordinating of trip settings and load shed plans. In the absence of a Commission directive to modify the Standard CenterPoint Energy does not agree that this expansion is necessary or required.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Kevin Koloini	American Municipal Power - Ohio	4	Disapprove	Conflict with PRC-006 and PRC-010.
Ajay Garg	Hydro One	1	Disapprove	Conflict with PRC-006.Addition of applicable entities is not "low hanging fruit."

Voter	Entity	Segment	P 601	Comments
	Networks, Inc.			
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Rex A Roehl	Indeck Energy Services, Inc.	5	Disapprove	Delete R3.4. APPA was incorrect in suggesting coordination with GO's. The purpose is load shedding. The TO and BA can take into account the GO settings, but the standard deals with when there is a lack of generation and load shedding needs to happen, not be dependent upon the remaining generators. Coordination at that point is self-defeating.
Danny McDaniel	Cleco Power LLC	1	Disapprove	EOP-003 should only reference manual load shed and not automatic load shed. PRC standards should be used for the automatic load shed programs.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE does not support the change in R3 that requires a TOP and BA to coordinate its load shedding plans with the Regional Entity (RE). The RE is not a functional entity with reliability responsibility in the operating or planning horizons. The directive from FERC was to consider APPA's comments and not implement them verbatim and it should be noted in the ERO's consideration that the RE was disregarded as an entity having reliability functional responsibility but serves the compliance enforcement role of the standards.To address this directive, FE suggests a comment response to the directive similar to our position above with no change to the standard.Finally, its noted that the proposed changes for EOP-003 do not align with a parallel ballot of work associated with project 2007-01 (UFLS)that includes a revision to EOP-003. Coordination is needed in this regard as confusion will result in FERC's review/approval of the two projects. Changes from each project impacting EOP-003 are not reflected in the other.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	FE does not support the change in R3 that requires a TOP and BA to coordinate its load shedding plans with the Regional Entity (RE). The RE is not a functional entity with reliability responsibility in the operating or planning horizons. The directive from FERC was to consider APPA's comments and not implement them verbatim and it should be noted in the ERO's consideration that the RE was disregarded as an entity having reliability functional responsibility but serves the compliance enforcement role of the standards.To address this directive, FE suggests a comment response to the directive similar to our position above with no change to the standard.Finally, its noted that the proposed changes for EOP-003 do not align with a parallel ballot of work associated with project 2007-01 (UFLS) that includes a revision to EOP-003. Coordination is needed in this regard as confusion will result in FERC's review/approval of the two projects. Changes from each project

Voter	Entity	Segment	P 601	Comments
				impacting EOP-003 are not reflected in the other.
David A. Lapinski	Consumers Energy	3	Disapprove	Fundamentally, automatic load shedding must be designed and implemented in the planning time horizon, not in any of the operational time horizons, in that it must be implemented via installation of equipment in substations. Therefore, EOP-003 continues to duplicate, to some degree, NERC Standard PRC-007, in that the elements established for automatic load shedding per EOP-003 are the same as those generally addressed in Regional UFLS programs, and probably resemble those elements likely addressed in a NERC-wide UFLS standard, when such a standard is promulgated. This seems to raise the specter of double jeopardy. Similar concerns apply regarding automatic load shedding relative to NERC Standards PRC-010 and PRC-021. We suggest that R4 address frequency and voltage related factors only to the degree that similar functions related to UFLS/UVLS programs as discussed above are determined to not be adequate, and would be implemented via SCADA or other operator-triggered standards.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	If TOPs and Bas are required to coordinate with RCs, REs, and GOs, they should be included as applicable entities and have a requirement to participate in the coordination of plans with their TOPs and BAs.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	
Charles Locke	KCPL	3	Disapprove	It is inappropriate to include Regional Entities as an entity to coordinate load shedding. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to coordinate operating actions or schemes as defined in this Standard EOP-003. See definition below: Regional Entity - The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.

Voter	Entity	Segment	P 601	Comments
Michael Gammon	KCPL	1	Disapprove	It is inappropriate to include Regional Entities as an entity to coordinate load shedding. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to coordinate operating actions or schemes as defined in this Standard EOP-003. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	It is inapproppropriate to have two conflicting versions of the same standard out for comment/ballot simultaneously. See Project 2007-01.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	It is suggested that the SDT adopt the version included in Project 2007-01, if approved by the ballot body. Given that Projedct 2007-01 contains requirements related to underfrequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review eriod for the third draft and is therefore superior to the version proposed by this SDT and is further along in te standard development process.
Larry Akens	Tennessee Valley Authority	1	Disapprove	It is suggested that the SDT adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to underfrequency load shedding, contains modifications to revise EOP-003, is in the pre-ballot review period for the third draft and is further along in the standards development process.
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process.
John Bos	Muscatine Power & Water	3	Disapprove	MPW believes this Requirement could be clean-up with little effort. While R1 clearly addresses manual load shedding and R2 talks distinctly about automatic load shedding, R3 is rather ambiguous. If R3 is speaking about both automatic and manual, we would expect to see that stated. Also, what is meant by "coordination of load shedding plans?" What is required of a Balancing Authority or

Voter	Entity	Segment	P 601	Comments
				Transmission Operator for the coordination of load shedding plans?
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	Not sure what interconnected entities are; does this mean the whole interconnection? I think this should be "directly tied" or "neighboring" entities. In R3.3 the (s) in Reliability Coordinator(s) should be removed. We don't think there is a BA or TOP which is overseen by multiple RCs?
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	Paragraph 601 - Although we agree that the changes meet the FERC Directive, we suggest the this version is premature given that Project 2007-01 (Underfrequency Load Shedding) contains requirements related to under-frequency load shedding, already contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft. We suggest the SDT take no action on this revision pending the outcome of balloting in Project 2007-01. Both requirements are ambiguous. They call for the testing of plans - not testing of the actual capability of shedding load. The best I can figure out is that R8 calls for some level of testing that the TOP or BA can do on their own, while R9 calls for a full-blown drill involving all applicable parties. The “simulation” required for R8 probably refers to pretending to coordinate with other parties as opposed to using a training simulator or actually operating “test” relays that aren’t wired to breaker trip circuits. I’m thinking that if you did R9 annually instead of every two years, you would have R8 covered. If the PJM Emergency Procedures Drills would suffice for R9, then we do those twice per year. It is difficult to interpret the actual intent of these two requirements. They both need to be clarified.
John K Loftis	Dominion Virginia Power	1	Disapprove	Paragraph 601 - Although we agree that the changes meet the FERC Directive, we suggest the this version is premature given that Project 2007-01 (Underfrequency Load Shedding) contains requirements related to under-frequency load shedding, already contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft. We suggest the SDT take no action on this revision pending the outcome of balloting in Project 2007-01. Both requirements are ambiguous. They call for the testing of plans - not testing of the actual capability of shedding load. The best I can figure out is that R8 calls for some level of testing that the TOP or BA can do on their own, while R9 calls for a full-blown drill involving all applicable parties. The “simulation” required for R8 probably refers to pretending to coordinate with other parties as opposed to using a training simulator or actually operating “test” relays that aren’t wired to breaker trip circuits. I’m thinking that if you did R9 annually instead of every two years, you would have R8 covered. If the PJM Emergency Procedures Drills would suffice for R9, then we do those twice per year. It is difficult to interpret the actual intent of these two requirements. They both need to be clarified.
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 601: The Regional Entity does not have a load shed plan, therefore is nothing for Duke Energy to coordinate with them. Coordination entails determining what affect the Duke Energy Load Shed Plans would have on the various entities listed in R3 and its sub- requirements. Since the

Voter	Entity	Segment	P 601	Comments
				Regional Entity does not have a transmission system, and load attached to it, there is nothing to coordinate.
Scott Peterson	San Diego G&E	3	Disapprove	Project 2007-01: Underfrequency Load Shedding is a parallel effort to re-write EOP-003. There are inconsistencies between these two efforts. Combine the efforts into one and come up with one version. R9. Which Entity is the initiator of the test. R9: Clarify that personnel deployment drills and tests may be tabletop exercises. Every two years is too often.
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Disapprove	R3 requires a TOP and BA to coordinate load shedding plans with each interconnected TOP and BA along with Regional Entities within whose regions they operate and RC(s) associated with overseeing the operations of the BA or TOP, plus GOs within the appropriate BA area or TOP area. This multiple coordination effort harms reliability of the BES and will only add confusion and frustration. Many TOPs and BAs are registered within multiple regions and this proposed continent wide reliability standard does not take into consideration how present day entities support the BES, daily.The following is a proposed rewrite to R3 and its sub requirements:R3. Each Transmission Operator and Balancing Authority shall coordinate manual load shedding plans with at least one of the following:R3.1 Physically connected Transmission Operators and Balancing Authorities orR3.2 Regional Entities within whose regions they operate orR3.3 Reliability Coordinator(s) associated with overseeing the operations of the Balancing Authority Area or Transmission Operator Area andR3.4 Generator Owners within the Balancing Authority Area or Transmission Operator Area, as appropriate. The above rewrite now gives clarity with whom the TOP and BA is required to coordinate their manual load shedding plans with. Manual is inserted since UFLS and UVLS are noted within other standards and all load shedding (outside of UFLS and UVLS) is done manually. Presently many entities follow the Regional Entity's plan and this fulfills all sub requirements of R3.
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	R3 should specify it is manual load shedding or operator initiated loadhedding, so as not to be confused with ufls, uvls, or sps. R8 will require an interpretation of the word "simulation". Is a simulation having a single operator on a SCADA development system initiate a simulation, or a table top, or a planning study showing that load can be dropped?R9 will require clarification on whether this is a single test coordinated with all entities participating at the same time on an area basis. R9 item 2 states personnel deployment shall be included, but not every entity requires to dispatch personnel to deploy manual load shed. The phrase " as required by the manual load shed plan" should be added.
John Canavan	NorthWestern Energy	1	Disapprove	R8 would require BAs and TOPs to test their load shedding plans through simulation at least annually. Currently many BAs and TOPs do not have simulation capability. This requirement seems more applicable to a Regional Entity because in the Western Interconnection, the Regional Entity (RE)

Voter	Entity	Segment	P 601	Comments
				coordinates the regional UFLS Plan. Perhaps the RE should maintain this responsibility, or at least provide access to a simulator for the BAs and TOPs. Requiring each BA/TOP to have simulation software would be very expensive and would take much time and could require a longer phased-in implementation for this standard. Also, it is unclear whether this requirement applies to automatic load shedding or manual load shedding. R9 is also unclear whether this requirement applies to automatic load shedding or manual load shedding. In either case, such coordination to test load shed plans every two years among applicable TOPs, BAs, LSEs and DPs would be a very large effort, without much benefit to reliability. A suggestion for improvement might be to make the standard applicable only to entities with Load Shedding capability from Supervisory.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	Requirement R3 does not clarify the current ambiguity about what type ofload shedding - automatic or manual. R1 is clearly Automatic and APPA and ISONEtalk in Order 693 about "trip settings" which imply automatic as well.Furthermore, the UFLS drafting team has already proposed changes to EOP-003that are not coordinated with these changes to remove UFLS completely fromthis standard into of PRC-006. That set of changes to those standards will beballoted simultaneously with these changes based on the dates on NERC'swebsite.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	Requirement R3 does not clarify the current ambiguity about what type ofload shedding - automatic or manual. R1 is clearly Automatic and APPA and ISONEtalk in Order 693 about "trip settings" which imply automatic as well.Furthermore, the UFLS drafting team has already proposed changes to EOP-003that are not coordinated with these changes to remove UFLS completely fromthis standard into of PRC-006. That set of changes to those standards will beballoted simultaneously with these changes based on the dates on NERC'swebsite.
Gwen S Frazier	Gulf Power Co.	3	Disapprove	Requirement R3 does not clarify the current ambiguity about what type ofload shedding - automatic or manual. R1 is clearly Automatic and APPA and ISONEtalk in Order 693 about "trip settings" which imply automatic as well.Furthermore, the UFLS drafting team has already proposed changes to EOP-003that are not coordinated with these changes to remove UFLS completely fromthis standard into of PRC-006. That set of changes to those standards will beballoted simultaneously with these changes based on the dates on NERC'swebsite.
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
Michael F Gildea	Dominion Resources Services	3	Disapprove	requirements related to under-frequency load shedding, already contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft. We suggest the SDT take no action on this revision pending the outcome of balloting in Project 2007-01. Both requirements are ambiguous. They call for the testing of plans - not testing of the actual capability of shedding load. The best I can figure out is that R8 calls for some level of testing that the TOP or BA can do on their own, while R9 calls for

Voter	Entity	Segment	P 601	Comments
				a full-blown drill involving all applicable parties. The “simulation” required for R8 probably refers to pretending to coordinate with other parties as opposed to using a training simulator or actually operating “test” relays that aren’t wired to breaker trip circuits. I’m thinking that if you did R9 annually instead of every two years, you would have R8 covered. If the PJM Emergency Procedures Drills would suffice for R9, then we do those twice per year. It is difficult to interpret the actual intent of these two requirements. They both need to be clarified.
Donald S. Watkins	BPA	1	Approve	Requires test every 2 years with TOP/BA/LSE/DP and deployment of personnel (that's a ton of work for a large TOP). Requires annual simulation of load shedding plans (with the other revisions UF moves to Planning Coordinator not TOP/BA but does leave UVLS with the TOP). Adds - coordinate load shedding plans with RC, Regional Entity (and GO as appropriate?).
Brenda S. Anderson	BPA	6	Disapprove	
Rebecca Berdahl	BPA	3	Disapprove	
Dennis Sismaet	Seattle City Light	6	Disapprove	
Charles H Yeung	Southwest Power Pool	2	Disapprove	Taken in conjunction with the entire standard the change becomes a de facto acceptance of the requirement as written. Regarding R3, the concept of “coordination” is vague and undefined.
Gregory Campoli	NYISO	2	Disapprove	Taken in isolation the concept of adding a list of entities with whom the TOP and BA must coordinate is reasonable. Taken in conjunction with the entire standard the change becomes a de facto acceptance of the requirement as written. Regarding R3, the concept of “coordination” is vague and undefined. There are several issues that make this seemingly trivial request more complex than the requestor makes it out to be. o The standard itself is included in Project 2007-01 o The concept of “coordination” is vague and undefined o There is no measurement nor VSL for R3 o Who is non-compliant if one or more of the list entities does not participate? o Aren’t all TOPs and BAs in an interconnection “interconnected”?
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	
Terry L. Blackwell	Santee Cooper	1	Disapprove	The meaning of “coordinate” needs to be clarified. In addition, EOP-003-1 is in the pre-ballot review period for the third draft and those changes are not incorporated into this draft. It would be best to wait and let industry vet EOP-003-1 first before making more changes to this standard.
Kim Warren	IESO	2	Disapprove	The proposed changes are OK. However, a related project to revise PRC-006 is near completion. PRC-006 is now posted for balloting and commenting. Changes to PRC-006 include removing certain requirements from EOP-003. The proposed changes to EOP-003 to address Order 693 directive runs counter with the PRC-006 project. When PRC-006 and its acCo.ing EOP-003 changes are approved, the

Voter	Entity	Segment	P 601	Comments
				version used for the proposed EOP-003 changes to address Order 693 will become invalid.
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	the regional entity may summerize its member's load shed plan but typically the region doesn't have a load shed plan
Jason Shaver	ATC	1	Disapprove	The SDT should clarify if this requirement applies to either or both manual and automatic load shedding. ATC believes that this should only apply to manual load shedding
Doug Bantam	LES	1	Disapprove	The standard as currently drafted fails to consider proposed revision to Project 2007-01 which would eliminate references to a UFLS program in EOP-003-2. To avoid undermining the efforts of the Project 2007-01 drafting team, LES recommends removing EOP-003-2 from consideration.
Dennis Florom	LES	5	Disapprove	
Eric Ruskamp	LES	6	Disapprove	
Brian Evans-Mongeon	Utility Services, Inc.	8	Disapprove	The UFLS SDT has contemplated changes and these proposals conflict with the SDT's efforts.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	There are currently two versions of a revision to EOP-003 out for ballot; one as part of this Order 693 and the other as part of the PRC-006, Project 2007-01 effort. These revision conflict with one another. UFLS and UVLS should be addressed in the PRC standards with only reference to manual load shedding, not automatic load shedding.
Mel Jensen	APS	5	Disapprove	There are two versions of a revision to EOP-003 out for ballot at the same time (now), one as part of this Order 693 effort and another as part of the PRC-006, Project 2007-01 effort. The revisions do not complement each other but rather conflict with each other. The PRC-006 team is proposing to remove UFLS from the EOP-003 standard because it really does not belong there and belongs instead in PRC-006. In all honesty, UVLS ought to also be removed from EOP-003 in favor of PRC-010 as well, but, that will presumably be left to another drafting team (presumably Project 2008-02). But, the real point here is that EOP-003 is broken, ought to only refer to manual load shedding, not automatic (automatic should be handled in PRC standards), and the two teams have made conflicting proposals on how to fix EOP-003 that ought to be coordinated. EOP-003, as proposed, is disturbing in the sense that it requires simulation of the effectiveness of load shedding plan (R7- new) and test of load shedding plan (R8-new), without specifying the scope and clarifying what it means.
Robert D Smith	Arizona Public Service Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	These new provisions are in conflict with the proposed PRC_006 NERC standard, and should be addressed in this forum.There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9. Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive.

Voter	Entity	Segment	P 601	Comments
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	These new provisions are in conflict with the proposed PRC-006 NERC standard, and should be addressed in this forum. There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9. Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive.What are personnel deployment drills? Are these applicable to automatic load shedding?
Randall McCamish	City of Vero Beach	1	Disapprove	This is probably a case of miscommunication between Drafting Teams under tight time pressure, but, there are two versions of a revision to EOP-003 out for ballot at the same time (now), one as part of this Order 693 effort and another as part of the PRC-006, Project 2007-01 effort. The revisions do not compliment each other but rather conflict with each other. The PRC-006 team is proposing to remove UFLS from the EOP-003 standard because it really does not belong there and belongs instead in PRC-006. In all honesty, UVLS ought to also be removed from EOP-003 in favor of PRC-010 as well, but, that will presumably be left to another drafting team (presumably Project 2008-02). But, the real point here is that EOP-003 is broken, ought to only refer to manual load shedding, not automatic (automatic should be handled in PRC standards), and the two teams have made conflicting proposals on how to fix EOP-003 that ought to be coordinated.
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	This is probably a case of miscommunication between Drafting Teams under tight time pressure, but, there are two versions of a revision to EOP-003 out for ballot at the same time (now), one as part of this Order 693 effort and another as part of the PRC-006, Project 2007-01 effort. The revisions do not compliment each other but rather conflict with each other. The PRC-006 team is proposing to remove UFLS from the EOP-003 standard because it really does not belong there and belongs instead in PRC-006. In all honesty, UVLS ought to also be removed from EOP-003 in favor of PRC-010 as well, but, that will presumably be left to another drafting team (presumably Project 2008-02). But, the real point here is that EOP-003 is broken, ought to only refer to manual load shedding, not automatic (automatic should be handled in PRC standards), and the two teams have made conflicting proposals on how to fix EOP-003 that ought to be coordinated.
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We disagree with the changes to address the directives in paragraph 601. No where does the directive require changes to be made. It only requires consideration of changes. How was this consideration made? Our understanding is that no drafting team was ever convened to discuss these changes. Thus, on this merit alone, the changes should be removed to be considered by a drafting team. Furthermore, the UFLS drafting team has already proposed changes to EOP-003 that are not coordinated with these changes to remove UFLS completely from this standard into of PRC-006. That set of changes to those standards will be balloted simultaneously with these changes based on the dates on NERC's website. Coordinating load shedding plans with regional entities does not make any

Voter	Entity	Segment	P 601	Comments
				sense in today's environment and is a vestige of the pre-enforcement area. The regional entities have no operating responsibilities and all the legal authority they need to review/request a registered entity's load shedding plan. We are not convinced that the load shedding should be coordinated with the RC. Clearly, the RC should be made aware of load shedding plans and capabilities. Any coordination, however, would be of the automatic load shedding plans and should probably occur through the PC. That is precisely what the UFLS project is proposing that will be balloted simultaneously with this set of changes.Adding sub-requirements R3.1 through R3.4 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Alan Gale	City of Tallahassee	5	Disapprove	Why is the RE included? Aren't they responsible for Compliance? I agree with the RC.Doesn't this contradict, or conflict, with project 2007-01?
Raj Rana	AEP	3	Disapprove	With respect to R3.4., AEP recommends that it would be more applicable for the coordination to occur between Transmission Operator (TOP) or BA and Generator Operators rather than Generation Owners. In many cases, these are separate entities and it is our experiences that the GO is not always the appropriate entity regarding the sharing of these plans.AEP does not see the benefit in sharing the load shedding plans with the RE. Based on the division of responsibilities, some RE's mainly only have compliance staff and do not have expertise with addressing the plan. If a particular RE wanted to see the plan, AEP would work with that entity. Creating a process to send data to entities that do not need the information, simply for the sake of demonstrating compliance, does not advance the goal of increasing reliability.
Edward P. Cox	AEP Marketing	6	Disapprove	
Brock Ondayko	AEP Service Corp.	5	Disapprove	

Summary Consideration for changes related to P603:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 603	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	APPA	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Brenda Powell	Constellation	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael	Exelon Nuclear	5	Abstain	

Voter	Entity	Segment	P 603	Comments
Korchynsky				
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Kenneth Simmons	Gainesville Regional Utilities	3	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
Donald Gilbert	JEA	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Michael T. Quinn	Oncor Electric Delivery	1	Abstain	

Voter	Entity	Segment	P 603	Comments
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Jeff Nelson	Springfield Utility Board	3	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Liam Noailles	Xcel Energy, Inc.	5	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Donald S. Watkins	BPA	1	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	

Voter	Entity	Segment	P 603	Comments
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Steven M. Jackson	MEAG	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Approve	
Mark A. Heimbach	PPL Generation LLC	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	

Voter	Entity	Segment	P 603	Comments
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Daniel Herring	Detroit Edison Co.	4	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	

Voter	Entity	Segment	P 603	Comments
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Dan R. Schoenecker	MRO	10	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K	Northern Indiana	5	Disapprove	

Voter	Entity	Segment	P 603	Comments
Wilkerson	Public Service Co.			
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Bruce Glorvigen	OTP Wholesale Marketing	6	Disapprove	
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
John Apperson	PacifiCorp	3	Disapprove	
Mark Sampson	PacifiCorp	1	Disapprove	
Sandra L. Shaffer	PacifiCorp	5	Disapprove	
Greg Lange	Public Utility District No. 2 of Grant County	3	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Steve McElhaney	South Mississippi Electric Power	4	Disapprove	

Voter	Entity	Segment	P 603	Comments
	Association			
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(b) R9 requires to coordinate with LSE and DP. But the standard does not apply to LSE or DP and for that reason would be difficult to coordinate with them.
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. These new provisions are in conflict with the proposed PRC-006 NERC standard, and should be addressed in this forum. 2. There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9.3. What are personnel deployment drills? Are these applicable to automatic load shedding? 4. Requirement R9 is not in the directive; and is outside the scope of the directive.
Greg C Parent	Manitoba Hydro	3	Disapprove	603 - the level of coordination and number of personnel required to be deployed every 2 years to conduct these drills of simulated load shed will result in significant costs which far outweigh the benefits derived from the exercise. Requirements R8 (annual tests of load shedding plans via simulations) coupled with the proposed Modified Section B Requirement R3 (expanded coordination between entities) should be enough. Additionally, neither of these simulations have been done before and may involve a lot of software programming and data input, which could take a large period of

Voter	Entity	Segment	P 603	Comments
				time and manpower.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	a) Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process.b) Paragraph 603 - The comments indicate Section B, Requirements R9 and R10 - in reality, is itSection A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with theintent without actually shedding load. Tabletop exercises should be acceptable. R9 also expands theapplicability to load serving entities and distribution providers, which are not applicable to this standard.c) It isn’t clear what Measure M2 refers to now. The VSL requirement changes appear to be misnumbered.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	a) Although we agree the changes meet the FERC Directive, we suggest that the standard drafting team adopt the version included in Project 2007-01, if approved by the ballot body. Given that Project 2007-01 contains requirements related to under-frequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the 3rd draft, we feel that Project 2007-01 is superior to the version proposed by this SDT and is further along in the standards development process.b) Paragraph 603 - The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. Tabletop exercises should be acceptable. R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard.c) It isn’t clear what Measure M2 refers to now. The VSL requirement changes appear to be mis-numbered.
Harold Taylor, II	GTC	1	Disapprove	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	Add a not Addition of applicable entities is not "low hanging fruit."Need to explain the meaning of "personnel deployment drills."
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
John Tolo	Tucson Electric Power Co.	1	Disapprove	Agree with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. Also believe that once every two years is too often. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. Also believe that new Measures should be

Voter	Entity	Segment	P 603	Comments
				developed for any added Requirements.
Louise McCarren	WECC	10	Disapprove	Agree with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. Believe that once every two years is too often. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. Even if not specifically identified in Order 693, new Measures should be developed for any added Requirements.
Glen Reeves	Salt River Project	5	Disapprove	Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. We also believe that once every two years is too often. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. We also believe that new Measures should be developed for any added Requirements.
John T. Underhill	Salt River Project	3	Disapprove	
Robert Kondziolka	Salt River Project	1	Disapprove	
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Brock Ondayko	AEP Service Corp.	5	Disapprove	Comments: Drills should be and are already covered under the training standards. There is no need to have redundant requirements that create overlaps. Furthermore, the addition of R9 does not seem to be justified as part of the FERC directive in Paragraph 603.
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	commission language much clearer than the proposed R8 and R9. Drills vs Tests leave a lot of room open for interpretation.
Kevin Koloini	American Municipal Power - Ohio	4	Disapprove	Conflict with PRC-006 and PRC-010.
Paul Morland	Colorado Springs Utilities	1	Disapprove	CSU agrees with the concept of R8 but more clarity needs to be added to the language of R9, specifically with reference to personnel deployment drills. Table-top drills in our opinion would be adequate.
Terry L Baker	Platte River Power Authority	3	Disapprove	Delete R8. Having both R8 and R9 is confusing. Order 693 requires “periodic drills of simulated load shedding.” (Ballot seems to incorrectly reference R9 and R10.)

Voter	Entity	Segment	P 603	Comments
John C. Collins	Platte River Power Authority	1	Disapprove	
Raj Rana	AEP	3	Disapprove	Drills should be and are already covered under the training standards. There is no need to have redundant requirements that create overlaps. Furthermore, the addition of R9 does not seem to be justified as part of the FERC directive in Paragraph 603.
Edward P. Cox	AEP Marketing	6	Disapprove	
Terry L. Blackwell	Santee Cooper	1	Disapprove	FERC directed these changes go through the Reliability Standards process. We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process. In addition, EOP-003-1 is in the pre-ballot review period for the third draft and those changes are not incorporated into this draft. It would be best to wait and let industry vet EOP-003-1 first before making more changes to this standard.
David A. Lapinski	Consumers Energy	3	Disapprove	Fundamentally, automatic load shedding must be designed and implemented in the planning time horizon, not in any of the operational time horizons, in that it must be implemented via installation of equipment in substations. Therefore, EOP-003 continues to duplicate, to some degree, NERC Standard PRC-007, in that the elements established for automatic load shedding per EOP-003 are the same as those generally addressed in Regional UFLS programs, and probably resemble those elements likely addressed in a NERC-wide UFLS standard, when such a standard is promulgated. This seems to raise the specter of double jeopardy. Similar concerns apply regarding automatic load shedding relative to NERC Standards PRC-010 and PRC-021. We suggest that R4 address frequency and voltage related factors only to the degree that similar functions related to UFLS/UVLS programs as discussed above are determined to not be adequate, and would be implemented via SCADA or other operator-triggered standards.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	It is inappropropriate to have two conflicting versions of the same standard out for comment/ballot simultaneously. See Project 2007-01.
Charles Locke	KCPL	3	Disapprove	It is unclear as to the extent a "simulation" is intended in requirement R8. Recommend clarifying the simulation as a form of modeling and not intended as exercise of actual actions. In addition, what is to be simulated here? There are two forms of load shedding action. Automatic load shedding based on frequency and/or voltage and manual load shedding by operator action. What is the intention? It is unclear what "test" in requirement R9 represents. Recommend clearly indicating the intent is a test of the plans under table-top drills or other modeling techniques.
Michael Gammon	KCPL	1	Disapprove	
Richard J. Mandes	Alabama Power Co.	3	Disapprove	NERC Comments note revisions for R9 & R10, but R10 does not exist onpublished copy of draft. R8 & R9 appear to be the ones added. Also has incorrectreferences to R9 & R10 in VSL. And again, what

Voter	Entity	Segment	P 603	Comments
Anthony L Wilson	Georgia Power Co.	3	Disapprove	type of load shedding? In R8,the term “simulation” needs to be better defined to allow entities to comply withthe intent without actually shedding load.
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
Saurabh Saksena	National Grid	1	Disapprove	o National Grid seeks clarification and possible examples for the term “simulation”. o There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9 where LSE and DP have been added but are not included in the Applicability section. o What are personnel deployment drills? Are these applicable to automatic load shedding? o Requirement R9 is not in the directive; and is outside the scope of the directive.
Kim Warren	IESO	2	Disapprove	Paragraph 603 asks for including a requirement for periodic drills of simulated load shedding. The wording in R8 (which should read R9) asks for testing the load shedding plan through simulation. There was already a dispute on the interpretation of “simulation” (in a recently posted interpretation), which may be interpreted as using simulator or computer simulation program. The directive simply requires a “drill” which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation. Requirement R8 as written goes outside of the scope of the directive. On the other hand, R8 should include testing the readiness and functionality of procedures for system operators as well as distribution personnel and LSEs as per Paragraphs 596 and 597 respectively.Requirement R9 (which should read R10) is not asked for by the directive; it goes outside of the scope of the directive. Further, which entities need to participate in the testing of the plan and the required testing details need much more time and industry discussion to develop, and hence should be developed through the normal process not through this much abbreviated process. In addition, the meaning of the term “personnel deployment drills” in a requirement that asks for testing of the load shedding plan. It is more appropriate to clearly stipulate the intent or expected outcome of the drill rather than stipulating a term that is subject to different interpretation. It follows that we do not agree with the VSLs for this Requirement. Furthermore, Section 4 of this standard should also include Load Serving Entity and Distribution Provider to be consistent with this requirement.

Voter	Entity	Segment	P 603	Comments
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	Paragraph 603 -R8 The term “simulation” needs to be better defined to allow entities to comply with the intent without increasing the potential for shedding load to be inadvertently implemented. R9 expands the applicability to load serving entities and distribution providers, which are not listed in the Applicability section of this draft standard. We suggest the SDT either add these entities to the Applicability section or remove these entities from R9. Both requirements are ambiguous. They call for the testing of plans - not testing of the actual capability of shedding load. The best I can figure out is that R8 calls for some level of testing that the TOP or BA can do on their own, while R9 calls for a full-blown drill involving all applicable parties. The “simulation” required for R8 probably refers to pretending to coordinate with other parties as opposed to using a training simulator or actually operating “test” relays that aren’t wired to breaker trip circuits. I’m thinking that if you did R9 annually instead of every two years, you would have R8 covered. If the PJM Emergency Procedures Drills would suffice for R9, then we do those twice per year. It is difficult to interpret the actual intent of these two requirements. They both need to be clarified.
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
John K Loftis	Dominion Virginia Power	1	Disapprove	
Michael F Gildea	Dominion Resources Services	3	Disapprove	
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 603: With regards to R8, how is an entity expected to ï¿½simulate load shedï¿½ in order to demonstrate compliance with this requirement? The intent of the Order appears to be for an entity to train its operators on how to initiate load shed if required. It should be clear that an entity should not be required to take physical actions on the system to determine whether the load shed operations work properly (such as testing that a signal is sent to the field, which could require lifting leads from relays or otherwise blocking signals, introducing an unacceptable risk). Here is a proposed rewrite of R8: " At least annually, each Transmission Operator and Balancing Authority shall perform a simulation drill of their load shedding plans. [Violation Risk Factor: Low[Time Horizon: Long-term Planning, Operations Planning]".Here is a corresponding proposed rewrite of R9: ï¿½At least every two years, each Transmission Operator, Balancing Authority, Load Serving Entity, and Distribution Provider shall participate in a simulation drill of the applicable load shedding plans. Such drill shall include 1) coordination between Load Serving Entities, Distribution Providers, and the initiator of the simulation drill, and 2) personnel deployment drills. [Violation Risk Factor: Low [Time Horizon: Long-term Planning, Operations Planning]
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Disapprove	PG&E agrees with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. PG&E believes that once every two years is too often. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. PG&E also believes that new Measures should be developed for any added Requirements.In addition, some clarification is needed for EOP-003-2.

Voter	Entity	Segment	P 603	Comments
				The purpose statement leaves the impression that this standard concerns decisions that need to be made regarding manual load shedding in real time. Yet R2, R4, R6, R7 and M1 govern automatic load shedding, where real time decision is not anticipated. PG&E understands that this part of the comment may be out of scope for this ballot. However, it would be beneficial to clarify this standard either through a SAR or an interpretation.
Scott Peterson	San Diego G&E	3	Disapprove	Project 2007-01: Underfrequency Load Shedding is a parallel effort to re-write EOP-003. There are inconsistencies between these two efforts. Combine the efforts into one and come up with one version. R9. Which Entity is the initiator of the test. R9: Clarify that personnel deployment drills and tests may be tabletop exercises. Every two years is too often.
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	R3 should specify it is manual load shedding or operator initiated loadhedding, so as not to be confused with ufls, uvls, or sps. R8 will require an interpretation of the word “simulation”. Is a simulation having a single operator on a SCADA development system initiate a simulation, or a table top, or a planning study showing that load can be dropped?R9 will require clarification on whether this is a single test coordinated with all entities participating at the same time on an area basis. R9 item 2 states personnel deployment shall be included, but not every entity requires to dispatch personnel to deploy manual load shed. The phrase “ as required by the manual load shed plan” should be added.
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Disapprove	R8 (Note this requirement does not match up with NERCs Comment column above) Request that in order to prove clarity, R8 be rewritten as FERC stated within Order 693 to require periodic drills of simulated load shedding. R8 to read “At least annually, each Transmission Operator and Balancing Authority shall simulate load shedding as stated within their respected load shedding plan”. This rewrite will enable the TOP or BA to simulate load shedding as they plan, not practice load shedding by the use of simulation. R9 (Note this requirement does not match up with NERCs Comment column above) R9 should be deleted in its entirety since paragraph 603 states “ 603. The Commission approves proposed Reliability Standard EOP-003-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and Â§ 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-003-1 through the Reliability Standards development process that: (1) includes a requirement to develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on an overarching criteria that take into account system characteristics and (2) requires periodic drills of simulated load shedding”. R9 does not address the Commissions interests.
Brandy A	WAPA	1	Disapprove	R8 and R9 seem redundant. R8 requires testing of Load Shed Plan ANNUALLY, and R9 requires testing of Load Shed Plan at least every two years. First, annually is a little excessive, especially through

Voter	Entity	Segment	P 603	Comments
Dunn				simulation. We recommend getting rid of R8 entirely and clarifying in R9 that table top simulation can be used.
Laurie Williams	Public Service Co. of New Mexico	1	Disapprove	R8 doesn't seem required by Paragraph 603 and R9 should be changed to add some additional specificity to items such as the personnel deployment drills and table top exercises - every two years seems to be too often.
John Canavan	NorthWestern Energy	1	Disapprove	R8 would require BAs and TOPs to test their load shedding plans through simulation at least annually. Currently many BAs and TOPs do not have simulation capability. This requirement seems more applicable to a Regional Entity because in the Western Interconnection, the Regional Entity (RE) coordinates the regional UFLS Plan. Perhaps the RE should maintain this responsibility, or at least provide access to a simulator for the BAs and TOPs. Requiring each BA/TOP to have simulation software would be very expensive and would take much time and could require a longer phased-in implementation for this standard. Also, it is unclear whether this requirement applies to automatic load shedding or manual load shedding. R9 is also unclear whether this requirement applies to automatic load shedding or manual load shedding. In either case, such coordination to test load shed plans every two years among applicable TOPs, BAs, LSEs and DPs would be a very large effort, without much benefit to reliability. A suggestion for improvement might be to make the standard applicable only to entities with Load Shedding capability from Supervisory.
John Bos	Muscatine Power & Water	3	Disapprove	R9 and R10 will need direction for what is to be considered a valid simulation of load shedding plans. MPW feels these requirements are incredibly vague.
Danny McDaniel	Cleco Power LLC	1	Disapprove	R9 is too vague and does not include any guidance on the type of test to be implemented. Additional details are required for R9.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	R9 is too vague and does not include any guidance on the type of test to be implemented. Additional details are required for R9.
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	Regional entities should be struck from R3 as unnecessary to meet the paragraph 601 directive. Regional Entities do not operate the system and there is no need to coordinate load shedding plans with them. For R8 and paragraph 603, use FERC wording “At least annually TO and BA shall perform periodic drills of simulated load shedding” for R8 only. R9 should be deleted. There is no FERC directive or requirement for R9 in Order 693.
Doug Bantam	LES	1	Disapprove	Request that in order to prove clarity, R8 be rewritten as FERC stated within Order 693 to require periodic drills of simulated load shedding. R8 to read “At least annually, each Transmission Operator
Dennis	LES	5	Disapprove	

Voter	Entity	Segment	P 603	Comments
Florom				and Balancing Authority shall simulated load shedding as stated within their respected load shedding plan". This rewrite will enable the TOP or BA to simulate load shedding as they plan, not practice load shedding by the use of simulation.
Eric Ruskamp	LES	6	Disapprove	
Thomas E Washburn	FMPP	6	Disapprove	Requirement 8 should use the directive language ==> At least annually, each Transmission Operator and Balancing Authority perform a drill simulating their load shedding plan. Comment - since the actual load shed manually is different for each emenrgency condition. The manual load shed plan is have to cover hundreds or thousands for a larger system of variation.The directive does not state to test the load shedding plan through simulation.
Charles H Yeung	Southwest Power Pool	2	Disapprove	Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive. Further, which entities need to participate in the testing of the plan and the required testing details need much more time and industry discussion to develop, and hence should be developed through the normal process not through this much abbreviated process. It follows that we do not agree with the VSLs for this Requirement.
Brenda S. Anderson	BPA	6	Disapprove	Requires test every 2 years with TOP/BA/LSE/DP and deployment of personnel (that's a ton of work for a large TOP). Requires annual simulation of load shedding plans (with the other revisions UF moves to Planning Coordinator not TOP/BA but does leave UVLS with the TOP). Adds - coordinate load shedding plans with RC, Regional Entity (and GO as appropriate?).
Francis J. Halpin	BPA	5	Disapprove	
Rebecca Berdahl	BPA	3	Disapprove	
Dennis Sismaet	Seattle City Light	6	Disapprove	Requires test every 2 years with TOP/BA/LSE/DP and deployment of personnel (that's a ton of work for a large TOP). Requires annual simulation of load shedding plans (with the other revisions UF moves to Planning Coordinator not TOP/BA but does leave UVLS with the TOP). Adds - coordinate load shedding plans with RC, Regional Entity (and GO as appropriate?).
Nickesha P Carrol	ConEd of NY	6	Disapprove	Reword Requirement 9. The Balancing Authority should coordinate and identify all entities, and then all identified entities must participate.
Wilket (Jack) Ng	ConEd of NY	5	Disapprove	
Christopher L de Graffenried	ConEd of NY	1	Disapprove	Reword Requirement R9. The Balancing Authority should coordinate and identify all entities, and then all identified entities must participate.

Voter	Entity	Segment	P 603	Comments
Peter T Yost	ConEd of NY	3	Disapprove	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Disapprove	see WECC comments
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	Simulation is a term that has drawn different interpretations from "Compliance". Is the intent computer simulations or table top simulations. Similarly I beleive compliance wil have differing interpretations for what constitutes a deployment drill. Therefore I believe the standard is too vaque.
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	Simulation of the load shed is a concern
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Disapprove	testing every two years with coordination between DP/LSE/TOP/BA is a drastic change from the requirement once every 5 years as it now stands. Current PRC=006-0 language requires regions to assess the effectiveness of their Under frequency Load Shedding Plans every five years.
Larry Akens	Tennessee Valley Authority	1	Disapprove	The comments indicate Section B, Requirements 9 and 10. In reality, it is Section A, Requirements 8 and 9. The term "simulation" needs to be better defined to allow entities to comply with the intent without actually shedding load. Requirement 9 also expands the applicability to load serving entities and distribution providers, who are not applicable to this standard.
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	
George R. Bartlett	Entergy Corporation	1	Disapprove	The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. Also, the words “personnel deployment drill” without proper clarity will lead to multiple interpretation and expectations (table top drill or actual mobilization to stations with our plans). These words have to be clarified.Paragraph 603 concerns the simulation of and periodic drills for load shedding plans. The added requirements R8 and R9 addressing Paragraph 603 contain the “Time Horizon: Long-Term Planning, Operations Planning”. We believe these requirements do not apply to Long-Term Planning Time Horizon and that term should be deleted.R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard and should not be included.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	The comments indicate Section B, Requirements R9 and R10 - in reality, is it Section A, R8 and R9? The term “simulation” needs to be better defined to allow entities to comply with the intent without actually shedding load. Also, the words “personnel deployment drill” without proper clarity will lead to multiple interpretation and expectations (table top drill or actual mobilization to stations with our plans). These words have to be clarified. Paragraph 603 concerns the simulation of and periodic

Voter	Entity	Segment	P 603	Comments
				drills for load shedding plans. The added requirements R8 and R9 addressing Paragraph 603 contain the “Time Horizon: Long-Term Planning, Operations Planning”. We believe these requirements do not apply to Long-Term Planning Time Horizon and that term should be deleted. R9 also expands the applicability to load serving entities and distribution providers, which are not applicable to this standard and should not be included.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	The comments indicated Section B, Requirements 9 and 10. In reality, it is Section A, Requirements 8 and 9. The term "simulation" needs to be better defined to allow entities to comply with the intent without actually shedding load. Requirement 9 also expands the applicability to load serving entities and distribution providers, who are not applicable to this standard.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	The Commission directed "periodic drills of simulated load shedding" and that it ought to be include "simulated load shedding" - i.e., the Commission is not expecting engineering simulations, but rather a drill that simulates the decision making during an emergency event. R8 and R9 states "test" which is open to interpretation.
Randall McCamish	City of Vero Beach	1	Disapprove	The Commissions language is much clearer than the proposed R8 and R9. The commission directed "periodic drills of simulated load shedding", which means they want us to perform drills. R8 and R9 changes the object to "test" which introduces ambiguity that is wide-open to numerous interpretations. R8 and R9 should be revised to clearly show that "drills" are required as directed by the Commission. "Drills" are much less open to interpretation than "tests". In addition, the Commission was clear that the "drill" they are directing ought to include as part of the exercise "simulated load shedding", which is clear that the Commission does not expect engineering simulations, but rather a drill that simulated the decision making environment operators would be exposed to. R8 as proposed introduces the same ambiguity that is currently within EOP-005-1 R7 by saying "test their load shedding plans through simulation". This introduces the ambiguity that has spurred requests for interpretation in EOP-005-1 R7: is simulation a "drill" or an engineering computer simulation? While FMPA believes that EOP-005-1 R7 also means a "drill", compliance has believed otherwise. Here it is clearly a drill that is required. We ought to stay away from words that add ambiguity such as "simulation" and "test" and stick with words that are more clear, like "drill". (Note that the ballot refers to R9 and R10 whereas the proposed draft adds R8 and R9 and there is no R10, we assume this is a typo in the ballot)
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	The Commissions language is much clearer than the proposed R8 and R9. The commission directed "periodic drills of simulated load shedding", which means they want us to perform drills. R8 and R9 changes the object to "test" which introduces ambiguity that is wide-open to numerous interpretations. R8 and R9 should be revised to clearly show that "drills" are required as directed by

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				the Commission. "Drills" are much less open to interpretation than "tests". In addition, the Commission was clear that the "drill" they are directing ought to include as part of the exercise "simulated load shedding", which is clear that the Commission does not expect engineering simulations, but rather a drill that simulated the decision making environment operators would be exposed to. R8 as proposed introduces the same ambiguity that is currently within EOP-005-1 R7 by saying "test their load shedding plans through simulation". This introduces the ambiguity that has spurred requests for interpretation in EOP-005-1 R7: is simulation a "drill" or an engineering computer simulation? While FMPA believes that EOP-005-1 R7 also means a "drill", compliance has believed otherwise. Here it is clearly a drill that is required. We ought to stay away from words that add ambiguity such as "simulation" and "test" and stick with words that are more clear, like "drill". (Note that the ballot refers to R9 and R10 whereas the proposed draft adds R8 and R9 and there is no R10, we assume this is a typo in the ballot)
Walt Gill	Lake Worth Utilities	1	Disapprove	The Commissions language is much clearer than the proposed R8 and R9. The commission directed "periodic drills of simulated load shedding", which means they want us to perform drills. R8 and R9 changes the object to "test" which introduces ambiguity that is wide-open to numerous interpretations. R8 and R9 should be revised to clearly show that "drills" are required as directed by the Commission. "Drills" are much less open to interpretation than "tests". In addition, the Commission was clear that the "drill" they are directing ought to include as part of the exercise "simulated load shedding", which is clear that the Commission does not expect engineering simulations, but rather a drill that simulated the decision making environment operators would be exposed to. R8 as proposed introduces the same ambiguity that is currently within EOP-005-1 R7 by saying "test their load shedding plans through simulation". This introduces the ambiguity that has spurred requests for interpretation in EOP-005-1 R7: is simulation a "drill" or an engineering computer simulation? While FMPA believes that EOP-005-1 R7 also means a "drill", compliance has believed otherwise. Here it is clearly a drill that is required. We ought to stay away from words that add ambiguity such as "simulation" and "test" and stick with words that are more clear, like "drill". (Note that the ballot refers to R9 and R10 whereas the proposed draft adds R8 and R9 and there is no R10, we assume this is a typo in the ballot)
Larry E Watt	Lakeland Electric	1	Disapprove	
Carolyn Ingersoll	Constellation Energy	3	Disapprove	The directive specifically states that there should be periodic drills of simulated load shedding" and CECD recommends R9 be modified to include testing through simulation of the applicable load shedding plan."
Gregory Campoli	NYISO	2	Disapprove	The directives ask for including requirement for periodic drills of simulated load shedding. The wording in R8 asks for testing the load shedding plan through simulation. There was already a dispute

Voter	Entity	Segment	P 603	Comments
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	on the interpretation of "simulation" (in a recently posted interpretation), which may be interpreted as using simulator or computer simulation program. The directive simply requires a "drill" which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation. Requirement R8 as written goes outside of the scope of the directive. Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive. Further, which entities need to participate in the testing of the plan and the required testing details need much more time and industry discussion to develop, and hence should be developed through the normal process not through this much abbreviated process. It follows that we do not agree with the VSLs for this Requirement. There is a coordination concern with Project 2007-01 that is currently underway. Project 2007-01 whose latest draft is being posted for balloting and comment proposes to revise EOP-003 by removing UFLS reference from the latter standard. If the PRC-006/EOP-003 pair is approved, it will render the version being used for making changes to address the low-hanging fruit directive invalid. Further, there should not be two versions of the same standard to be posted for balloting at the same time. We suggest that changes to EOP-003 to address the directives in Para. 601 and 603 be withheld until after the Board adopts the revised PRC-006-1 and EOP-003-1 if they receive ballot approval. If they fail, such work should be assigned to the Project 2007-01 SDT for inclusion in the next draft.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	The language in the directive states "... requires periodic drills of simulated load shedding." The R8 language is "At least annually, each Transmission Operator and Balancing Authority shall test their load shedding plans through simulation." The R8 language connotes much more than what is in the FERC directive. R9 is in the spirit of the FERC directive. The new requirements do not comport with the VSL's: R8 and R9 are added in Section A, R9 and R10 are listed in Section C.
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Daniel Prowse	Manitoba Hydro	6	Disapprove	The level of coordination and number of personnel required to be deployed every 2 years to conduct these drills of simulated load shed will result in significant costs which far outweigh the benefits derived from the exercise. Requirements R8 (annual tests of load shedding plans via simulations) coupled with the proposed Modified Section B Requirement R3 (expanded coordination between entities) should be enough. Additionally, neither of these simulations have been done before and may involve a lot of software programming and data input, which could take a large period of time and manpower.
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	The LSE and DP need to be added to the Applicability per R9.

Voter	Entity	Segment	P 603	Comments
Brian Evans-Mongeon	Utility Services, Inc.	8	Disapprove	The proposed language does not provide clarity on how drills are to be conducted. The proposal is insufficient to meet the directive requirements.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	The proposed new requirements for R8 and R9 are substantive technical topics that require further vetting and discussion and do not qualify as "low hanging fruit" directives which are the focus of this project.R9 seems to go beyond the directive and includes entities (LSE & DP) that were not added to the applicability section of the standard.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Jason Shaver	ATC	1	Disapprove	The SDT should clarify if this requirement applies to either or both manual and automatic load shedding. ATC believes that this should only apply to manual load sheddingATC believes that the SDT needs to clarify the term "personnel" as used in Requirement 9. Does this mean that everyone in the organization included in the load shedding plan(s) must participate in the development drills? Is it acceptable that only some of the folks that are included in the load shedding plan participate in the drill? The SDT needs to clearly identify the compliance obligations being set by this requirement.
Lee Schuster	Florida Power Corporation	3	Disapprove	The Section 4 Applicability lists only Transmission Operators and Balancing Authorities. However, the proposed new R9 applies also to LSEs and DPs. Therefore, LSEs and DPs need to be added to Section 4 Applicability. Also, there is no added R10 in the proposed EOP-003-2 as indicated on the ballot form for Paragraph 603.
James Eckelkamp	Progress Energy	6	Disapprove	
Wayne Lewis	Progress Energy Carolinas	5	Disapprove	The Section 4 Applicability lists only Transmission Operators and Balancing Authorities. However, the proposed new R9 applies also to LSEs and DPs. Therefore, LSEs and DPs need to be added to Section 4 Applicability. Also, there is no added R10 in the proposed EOP-003-2 as indicated on the ballot form for Paragraph 603.
Mel Jensen	APS	5	Disapprove	There are two versions of a revision to EOP-003 out for ballot at the same time (now), one as part of this Order 693 effort and another as part of the PRC-006, Project 2007-01 effort. The revisions do not complement each other but rather conflict with each other. The PRC-006 team is proposing to remove UFLS from the EOP-003 standard because it really does not belong there and belongs instead in PRC-006. In all honesty, UVLS ought to also be removed from EOP-003 in favor of PRC-010 as well, but, that will presumably be left to another drafting team (presumably Project 2008-02). But, the real point here is that EOP-003 is broken, ought to only refer to manual load shedding, not automatic (automatic should be handled in PRC standards), and the two teams have made conflicting proposals on how to fix EOP-003 that ought to be coordinated. EOP-003, as proposed, is disturbing in the sense that it requires simulation of the effectiveness of load shedding plan (R7- new) and test of load shedding plan (R8-new), without specifying the scope and clarifying what it means.
Robert D Smith	Arizona Public Service Co.	1	Disapprove	

Voter	Entity	Segment	P 603	Comments
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	These new provisions are in conflict with the proposed PRC-006 NERC standard, and should be addressed in this forum. There are new requirements adding applicable entities and they have not been referenced in the Applicability section of the standard. For example, refer to Requirement R9. Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive.What are personnel deployment drills? Are these applicable to automatic load shedding?
Alan Gale	City of Tallahassee	5	Disapprove	To what extend must the simulation be carried out to be acceptable? This has been an issue on recent audits. What is the intent of including "personnel deployment drills" in the 2-year drill?I do not agree with the object of R8 and R9 being to "test" the "plan". The commission asked for a "drill". Am I supposed to perform training and simulate the decision making process, or am I supposed to have a "computer based" simulation that "tests" the validity of the "plan"?
Jason L. Murray	AESO	2	Disapprove	We agree with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. We also believe that once every two years is too often. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. We also believe that new Measures should be developed for any added Requirements.
Eric Egge	Black Hills Corp	1	Disapprove	
John Yale	Chelan County Public Utility District #1	5	Disapprove	We agree with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. We also believe that once every two years is too often. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years.
Linda R. Jacobson	City of Farmington	3	Disapprove	We agree with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. We also believe that once every two years is too often. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. We also believe that new Measures should be developed for any added Requirements.
Jerome Murray	Oregon Public Utility Commission	9	Disapprove	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Disapprove	
Dana Wheelock	Seattle City Light	3	Disapprove	

Voter	Entity	Segment	P 603	Comments
Hao Li	Seattle City Light	4	Disapprove	
Pawel Krupa	Seattle City Light	1	Disapprove	We agree with the concept of Requirement R8 but do not believe that it is required by Paragraph 603. Clarity needs to be added to the language of R9; specifically in the reference to the personnel deployment drills and that the tests are table-top type tests. We also believe that once every two years is too often. Existing standard PRC-006-0 requires regions to assess the effectiveness of their Underfrequency Load Shedding Plans every five years. We also believe that new Measures should be developed for any added Requirements.
Bethany Wright	SMUD	5	Disapprove	
James Leigh-Kendall	SMUD	3	Disapprove	
Mike Ramirez	SMUD	4	Disapprove	
Tim Kelley	SMUD	1	Disapprove	
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We believe R8 and R9 miss the entire point of the directive. The directive appears to be focused on exercising the load shedding plans without actually shedding load. Specifically, the Commissions states “periodic drills of simulated load shedding”. We believe the Commission did not include “simulated” for the purpose of simulating load shedding in a power flow or dynamics study for instance. If they had intended this, the requirement would have applied to the PC or TP. Rather, we believe the Commission used the word “simulated” before load shed to make it clear they did not intend for actual load to be shed during the drills. Further support for this position can be gathered by reviewing the Commissions directives and understanding of the UFLS standards in Order 693.Furthermore, we believe R8 and R9 should be written and addressed by a standards drafting team. These are significant issues and testing of load shedding plans is no small task. Because it will require the coordination of multiple registered entities, only a standards drafting team with the appropriate participation would be in a position to assess the appropriate requirement here and how often the tests should occur. Otherwise, we could end up with a reduction in reliability with actual load being shed from failure to properly coordinate tests or to understand that they are tests being conducted to comply with NERC standards.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	What are new personnel deployment drills? Are these applicable to automatic load shedding?
Mace Hunter	Lakeland Electric	3	Disapprove	Why are "personnel deployment drills" included in a long term planning requirement?

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Raj Rana	AEP	3	In Favor	
Edward P. Cox	AEP Marketing	6	In Favor	
Brock Ondayko	AEP Service Corp.	5	In Favor	
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Donald S. Watkins	Bonneville Power Administration	1	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Russell A Noble	Cowlitz County PUD	3	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
George R. Bartlett	Entergy Corporation	1	In Favor	

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Stanley M Jaskot	Entergy Corporation	5	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
Brenda L Truhe	PPL Electric Utilities Corp.	1	In Favor	
Mark A. Heimbach	PPL Generation LLC	5	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
John T. Underhill	Salt River Project	3	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	In Favor	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	In Favor	
Bethany Wright	SMUD	5	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Tim Kelley	SMUD	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Opposed	
Francis J. Halpin	Bonneville Power Administration	5	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Danny McDaniel	Cleco Power LLC	1	Opposed	
Bryan Y Harper	Cleco Utility Group	3	Opposed	

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Daniel Herring	Detroit Edison Co.	4	Opposed	
Robert Smith	Duke Energy	5	Opposed	
Walter Yeager	Duke Energy Carolina	6	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Opposed	
Kenneth Simmons	Gainesville Regional Utilities	3	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
John Bos	Muscatine Power & Water	3	Opposed	
Gregory Campoli	New York Independent System Operator	2	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
David T. Anderson	Ocala Electric Utility	3	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Terri Pyle	Oklahoma Municipal Power Authority	4	Opposed	
John Apperson	PacifiCorp	3	Opposed	
Mark Sampson	PacifiCorp	1	Opposed	
Sandra L.	PacifiCorp	5	Opposed	

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Shaffer				
Tim Hattaway	PowerSouth Energy Cooperative	5	Opposed	
Wayne Lewis	Progress Energy Carolinas	5	Opposed	
Laurie Williams	Public Service Co. of New Mexico	1	Opposed	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Opposed	
Greg Lange	Public Utility District No. 2 of Grant County	3	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	
Terry L. Blackwell	Santee Cooper	1	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	
Richard McLeon	South Texas Electric Cooperative	1	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Charles H Yeung	Southwest Power Pool	2	Opposed	
RJames Rocha	Tampa Electric Co.	5	Opposed	
George T. Ballew	Tennessee Valley Authority	5	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Linda Horn	Wisconsin Electric Power Co.	5	Opposed	
James R. Keller	Wisconsin Electric Power Marketing	3	Opposed	
Anthony Jankowski	Wisconsin Energy Corp.	4	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Terry L Baker	Platte River Power Authority	3	Opposed	Already provided my opinion regarding Paragraph 420 VRFs and VSLs in voting question #10.
John C. Collins	Platte River Power Authority	1	Opposed	
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 603 in their current format, we cannot support the changes to the VSLs. Futhermore, the VSLs are mislabeled R9 and R10. They should be R8 and R9.This question 20 actually asked about paragraph 420 but we are assuming the intent was to ask about the VSLs for paragraph 603.
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Kevin Koloini	American	4	Opposed	Conflict with PRC-006 and PRC-010.

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
	Municipal Power - Ohio			
Mel Jensen	APS	5	Opposed	EOP-003, as proposed, is disturbing in the sense that it requires simulation of the effectiveness of load shedding plan (R7- new) and test of load shedding plan (R8-new), without specifying the scope and clarifying what it means.
Robert D Smith	Arizona Public Service Co.	1	Opposed	
David A. Lapinski	Consumers Energy	3	Opposed	Fundamentally, automatic load shedding must be designed and implemented in the planning time horizon, not in any of the operational time horizons, in that it must be implemented via installation of equipment in substations. Therefore, EOP-003 continues to duplicate, to some degree, NERC Standard PRC-007, in that the elements established for automatic load shedding per EOP-003 are the same as those generally addressed in Regional UFLS programs, and probably resemble those elements likely addressed in a NERC-wide UFLS standard, when such a standard is promulgated. This seems to raise the specter of double jeopardy. Similar concerns apply regarding automatic load shedding relative to NERC Standards PRC-010 and PRC-021. We suggest that R4 address frequency and voltage related factors only to the degree that similar functions related to UFLS/UVLS programs as discussed above are determined to not be adequate, and would be implemented via SCADA or other operator-triggered standards.
David Frank Ronk	Consumers Energy	4	Opposed	
James B Lewis	Consumers Energy	5	Opposed	
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Steve Alexanderson	Central Lincoln PUD	3	Opposed	It is inappropriate to have two conflicting versions of the same standard out for comment/ballot simultaneously. See Project 2007-01.
Brad Jones	Luminant Energy	6	Opposed	No opinion
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	Note that the question title says Paragraph 420, which we assume to be a typo and should refer to Paragraph 603. See comments to "Changes for Directives in Paragraph 603"
Randall McCamish	City of Vero Beach	1	Opposed	
Walt Gill	Lake Worth Utilities	1	Opposed	
Larry E Watt	Lakeland Electric	1	Opposed	
Mike Laney	Luminant	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
	Generation Co. LLC			
Kim Warren	IESO	2	Opposed	R5 needs to be changed first.
Charles Locke	Kansas City Power & Light Co.	3	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
Michael Gammon	Kansas City Power & Light Co.	1	Opposed	
Alan Gale	City of Tallahassee	5	Opposed	Requires clarification per Quuestion # 19.
Dennis Sismaet	Seattle City Light	6	Opposed	Requires test every 2 years with TOP/BA/LSE/DP and deployment of personnel (that's a ton of work for a large TOP). Requires annual simulation of load shedding plans (with the other revisions UF moves to Planning Coordinator not TOP/BA but does leave UVLS with the TOP). Adds - coordinate load shedding plans with RC, Regional Entity (and GO as appropriate?).
Saurabh Saksena	National Grid	1	Opposed	See comments above.
Ronald L Donahey	Tampa Electric Co.	3	Opposed	see comments for 19 above
Gregg R Griffin	City of Green Cove Springs	3	Opposed	see comments on 503
Carolyn Ingersoll	Constellation Energy	3	Opposed	The directive specifically states that there should be periodic drills of simulated load shedding" and CECD recommends R9 be modified to include testing through simulation of the applicable load shedding plan."
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	The directives ask for including requirement for periodic drills of simulated load shedding. The wording in R8 asks for testing the load shedding plan through simulation. There was already a dispute on the interpretation of "simulation" (in a recently posted interpretation), which may be interpreted as using simulator or computer simulation program. The directive simply requires a "drill" which is commonly understood to mean a mock exercise which does not necessarily require the use of a simulator or computer simulation. Requirement R8 as written goes outside of the scope of the directive. Requirement R9 is not asked for by the directive; it goes outside of the scope of the directive. Further, which entities need to participate in the testing of the plan and the required testing details need much more time and industry discussion to develop, and hence should be

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
				developed through the normal process not through this much abbreviated process. It follows that we do not agree with the VSLs for this Requirement. There is a coordination concern with Project 2007-01 that is currently underway. Project 2007-01 whose latest draft is being posted for balloting and comment proposes to revise EOP-003 by removing UFLS reference from the latter standard. If the PRC-006/EOP-003 pair is approved, it will render the version being used for making changes to address the low-hanging fruit directive invalid. Further, there should not be two versions of the same standard to be posted for balloting at the same time. We suggest that changes to EOP-003 to address the directives in Para. 601 and 603 be withheld until after the Board adopts the revised PRC-006-1 and EOP-003-1 if they receive ballot approval. If they fail, such work should be assigned to the Project 2007-01 SDT for inclusion in the next draft.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Opposed	The new VSLs should be for R8 & R9, not R9 & R10.
Rex A Roehl	Indeck Energy Services, Inc.	5	Opposed	The R9 VSL should be Moderate not Severe. The R10 VSL's should be Low and Moderate, not High and Severe.
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	The VSL numbering incorrectly references R9 and R10 instead of the correct R8 and R9 requirement additions.
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	The VSLs for R8 and R9 should be rewritten to match the above proposed rewritten requirements, and renumbered R8 and R9 instead of R9 and R10.
Louise McCarren	Western Electricity Coordinating Council	10		This appears to be a duplication of question 10.
Guy Andrews	Georgia System Operations Corporation	4	Opposed	VSL changes not numbered correctly. Refer to comments above.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	
Harold	GTC	1	Opposed	

Voter	Entity	Segment	P 603 VRFs and VSLs	Comments
Taylor, II				
Brandy A Dunn	Western Area Power Administration	1	Opposed	VSL's are numbered incorrectly as R9 and R10, whereas the Requirements they refer to are R8 and R9.
Timothy VanBlaricom	California ISO	2	Opposed	We believe the VSLs are inappropriately high for a simulation excersize.
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P612:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 612	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	American Public Power Association	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	

Voter	Entity	Segment	P 612	Comments
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Nickesha P	ConEd of NY	6	Approve	

Voter	Entity	Segment	P 612	Comments
Carrol				
Christopher L de Graffenried	ConEd of NY	1	Approve	
Wilket (Jack) Ng	ConEd of NY	5	Approve	
Peter T Yost	ConEd of NY	3	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Robert W. Roddy	Dairyland Power Coop.	1	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	

Voter	Entity	Segment	P 612	Comments
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Thomas E Washburn	FMPP	6	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Greg Froehling	Green Country Energy	5	Approve	
Kim Warren	IESO	2	Approve	
Jim D. Cyrulewski	JDRJC Associates	8	Approve	
Donald Gilbert	JEA	5	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	

Voter	Entity	Segment	P 612	Comments
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven Grego	MEAG Power	3	Approve	
Jason L Marshall	Midwest ISO, Inc.	2	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Robert Mattey	Ohio Valley Electric Corp.	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	

Voter	Entity	Segment	P 612	Comments
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade	6	Approve	

Voter	Entity	Segment	P 612	Comments
	LLC			
David Murray	PSEG Power LLC	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Daniel Baerman	San Diego G&E	5	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
William D Shultz	Southern Co. Generation	5	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	

Voter	Entity	Segment	P 612	Comments
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
Raj Rana	AEP	3	Disapprove	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Brenda Powell	Constellation Energy	6	Disapprove	

Voter	Entity	Segment	P 612	Comments
	Commodities Group			
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
Dan Roethemeyer	Dynegy Inc.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Brad Jones	Luminant Energy	6	Disapprove	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	
Dan R. Schoenecker	MRO	10	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Bruce	OTP Wholesale	6	Disapprove	

Voter	Entity	Segment	P 612	Comments
Glorvigen	Marketing			
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Scott Peterson	San Diego G&E	3	Disapprove	"Reportable incidents" is well defined and it is understood when to report. However, there is no definition of what constitutes a "disturbances" so as to know what events need to be provided to RC, BA, and TOP.
Kirit S. Shah	Ameren Services	1	Disapprove	(a) R3 - nalyze disturbance on GOP system is unclear or vauge. Drafting team should describe what is expected. (b) R3.1 - "analyze performance of their equipment" is vauge. Drafting team should

Voter	Entity	Segment	P 612	Comments
				describe what is expected or delete the requirement.
Wayne Lewis	Progress Energy Carolinas	5	Disapprove	“Disturbance” is a NERC-defined term, but the defined term is not used in the proposed EOP-004-2. Rather, “Bulk Electric System disturbance” is used. This term needs to be defined including consistency with Att. 1 NERC Disturbance Report Form.
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. 2. These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. 3. The RC and BA, responsible for analysis, most likely do not own much in the way of systems or facilities except for back-up facilities. The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 4. The new standard language in R3 and 3.1 suggests that any disturbance originating from outside of the applicable Registered Entity will have to be reported and there are no means for how the reporting is to be handled. 5. Why wasn't DP added to R4?
Daniel Duff	Liberty Electric Power LLC	5	Disapprove	A generator operator cannot know if their actions "could have resulted in a system disturbance as defined by 1-5 above". Further, the new requirement of "analyze the performance of their equipment" is unclear and needs better definition.
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	Addition of responsible entities is not low hanging fruit.A current SDT for the Disturbance/Sabotage Reporting standard should address this directive.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Mark Ringhausen	Old Dominion Electric Coop.	4	Approve	Agree, GO and LSEs do not have access to this information, typically.On R3, I think you need to add a request from the RC, BA or TOP to the GO or LSE as the GO/LSE may not know there was a disturbance and therefore, would not know to perform this analysis. Add- If requiested by a RC, BA or TOP.
Carolyn Ingersoll	Constellation Energy	3	Disapprove	APPA’s concerns appear to be with the inability to perform an analysis of a disturbance that originated outside of their system and with coordination between affected registered entities. The standard already specified that the registered entity must only perform an analysis of disturbances on “its system or facilities” so no modifications were required to address this issue. The second issue identified by APPA seems to be the coordination between affected parties. The proposed language in R3.1 partially addresses this issue by requiring coordination (information sharing) by

Voter	Entity	Segment	P 612	Comments
				the GOP, DP and LSE with their associated RC, BA , and TOP, however the RC, BA and TOP should also be required to share information with impacted entities.
Paul Rocha	CenterPoint Energy	1	Disapprove	CenterPoint Energy notes that in paragraph 612 the Commission directs the ERO to consider this concern regarding a GO and LSE's ability to analyze disturbances. The current R3 requires each RC, BA, TOP, GO and LSE to analyze System disturbances on its system or facilities, therefore CenterPoint Energy beleives the current language addresses these concerns.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Lee Schuster	Florida Power Corporation	3	Disapprove	Disturbance" is a NERC-defined term, but the defined term is not used in the proposed EOP-004-2. Rather, "Bulk Electric System disturbance" is used. This term needs to be defined including consistency with Att. 1 NERC Disturbance Report Form.
James Eckelkamp	Progress Energy	6	Disapprove	
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	Do not believe the proposed changes addresses the concerns of APPA as recognized by the Commission. The proposed requirements direct the Generator Operators and Load Serving Entities to "promptly analyze Bulk Electric System disturbances on its system or facilities" in R3 which APPA has a direct concern. Recommend modifying the requirement R3 and sub-requirement R3.1 to state that Generator Operators and Load Serving Entities provide data available from installed data recording systems, if they exist, upon request of other TOP's or BA's.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	don't see a need to promptly analyze events below 100 kV
Kevin Koloini	American Municipal Power - Ohio	4	Disapprove	DP applicability should be removed
Mike Laney	Luminant Generation Co. LLC	5	Disapprove	Generator Operators in ERCOT do not have the necessary data or applications needed to properly analyze a disturbance on the system or facilities as stipulated in R3. Therefore, Luminant believes this is not an appropriate requirement. It is appropriate for the GOP to submit a disturbance report when, for example, it looses a facility that caused or impacted the disturbance.Luminant can support R3.1 in providing information or data to those entities who have the ability to analyze these disturbance impacts to the system. However, Luminant feels that information provided

Voter	Entity	Segment	P 612	Comments
				should be "at the request" of the Reliability Coordinator, Balancing Authority, and Transmission Operator. A GOP may need to provide additional information to these entities not covered on the original disturbance report. In this case, the entities capable of performing the study should make a specific request for the additional information needed. This approach would seem to be more auditable as well.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	In EOP-004 R3.1 the introductory words “At a minimum” imply that more action than stated might be needed to be compliant but the requirement does not elaborate on what additional steps might be required. “At a minimum” adds nothing to the requirement except ambiguity and should be deleted. FERC never said that we have to take the exact wording from their order and insert it into the standard. The ambiguity is compounded by structuring R3 as a requirement and sub requirement. We recommend deleting R3.1 and rewriting R3 as follows:Each Generator Operator, Distribution Provider, and Load Serving Entity shall promptly analyze the performance of its equipment in reacting to a Bulk Electric System disturbance on its system or facilities and provide the results of its analysis to its Reliability Coordinator, Balancing Authority, and Transmission Operator.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	In EOP-004 R3.1 the introductory words “At a minimum” imply that more action than stated might be needed to be compliant but the requirement does not elaborate on what additional steps might be required. “At a minimum” adds nothing to the requirement except ambiguity and should be deleted. FERC never said that we have to take the exact wording from their order and insert it into the standard. The ambiguity is compounded by structuring R3 as a requirement and sub requirement. We recommend deleting R3.1 and rewriting R3 as follows:Each Generator Operator, Distribution Provider, and Load Serving Entity shall promptly analyze the performance of its equipment in reacting to a Bulk Electric System disturbance on its system or facilities and provide the results of its analysis to its Reliability Coordinator, Balancing Authority, and Transmission Operator.Also, as a general statement this standard refers to Regional Reliability Organization instead of Regional Entity.The Measures refer to Requirements R3.1 and R3.3. We believe they should refer to R4.1 and R4.3 now.
Charles H Yeung	Southwest Power Pool	2	Disapprove	In the context of the entire requirement, the proposed changes to R2 and R3 are vague as written. The requirements mandate “prompt analysis”. FERC has requested NERC to avoid that kind of ambiguous phrase.The sub requirement R3.1 emasculates the main requirement by introducing “at a minimum”. From the FERC directive, it seems that only the sub requirement is needed and the main requirement should be deleted.

Voter	Entity	Segment	P 612	Comments
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	In the new R3, R3.1; the phrase “analyze the performance of their equipment...” is unreasonably vague and seems to be a net intended to gather in all DP’s. A more reasonable statement would be “BES equipment...”.
David A. Lapinski	Consumers Energy	3	Disapprove	It is unclear as to what constitutes a disturbance. Does a disturbance, in the context of R2 and R3, constitutes a simple fault that is observable on the BES but normally cleared, or is it more limited. As written, these requirements could be interpreted to trigger thousands of “disturbance investigations” annually, the vast majority of which have no impact. Additionally, Attachment 2 (unchanged in this draft) purports to summarize OE-417 reporting requirements, but has a number of inaccuracies related to Attachment 2 timeliness requirements as compared to OE-417 reporting requirements (many of the elements with 1-hour reporting on Attachment 2 have 6-hour reporting on OE-417). It must be clarified whether Attachment 2 defines NERC requirements, or whether, for events described on OE-417, that OE-417 timeliness requirements govern. It should also be considered, relative to 1-hour reporting on Attachment 2, that, in the initial hour or two of an actual event, operating personnel will be fully engaged in determining the scope of the event and in addressing immediate operating concerns, and that they would be distracted from immediate reliability-related activities to prepare and file a report. Relative to R3 and the related VSL, “promptly” is a very subjective term, and is likely to lead to contention when evaluating compliance. Finally, there is unresolved duplication between this standard (Attachment 2, Incident No 5) and CIP-001 regarding sabotage incidents, and Attachment 2, Incident No 6 and CIP-008 regarding cyber incidents. We feel that the changes in this draft do not offer any improvement in the quality of this standard, and that, given the major problems with EOP-004-1, that the entire standard must be re-written, given due consideration to the inconsistencies with OE-417 and the inadvertent duplication with CIP-001 and CIP-006.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Approve	It's not clear in R3.1 how an entity is to “provide” information to the specified entities. The addition of DP to R3, but not to R4 is confusing.
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 612: (R3). Duke Energy disagrees with Distribution Providers needing to promptly analyze Bulk Electric System disturbances on its system or faculties below 100 kV. Order 693, as it defines Bulk Electric System, does not include the Distribution System (Paragraph 52 of Order 693).Paragraph 612: (R3.1). Analysis of the performance of equipment owned by the GO, DP, or LSE is not communicated to the Reliability Coordinator. This information is communicated by these entities to the Balancing Authority and/or Transmission Provider who in turn communicates the information to the Reliability Coordinator.

Voter	Entity	Segment	P 612	Comments
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	R2 in EOP-004-2 requires entities to 'promptly' analyze BES disturbances. Ambiguity in different definitions of prompt will create confusion. The requirement is vague.
Mark A. Heimbach	PPL Generation LLC	5	Approve	R3.1 - "At a minimum" adds confusion.
Brenda L Truhe	PPL Electric Utilities Corp.	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	Requirement R2 requires applicable entities to "promptly" analyze Bulk Electric System disturbances. There is no definition for the term promptly, and therefore the Requirement is vague. Consider replacing the word promptly with a definitive description of the time limiations for analyzing different types of disturbances
Linda R. Jacobson	City of Farmington	3	Approve	Requirement R2 requires applicable entities to promptly analyze Bulk Electric System disturbances. There is no definition for the term promptly, and therefore the Requirement is vague.
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	Requirement R2 requires applicable entities to promptly analyze Bulk Electric System disturbances. There is no definition for the term promptly, and therefore the Requirement is vague. In addition, EOP-004 Disturbance reporting for generation (R3) has been modified to include an analysis of the disturbance on generation systems. However, it is unclear as to when such an evaluation is required. If there has been no impact on generation, i.e. trip, instability, etc., this seems to be a frivolous requirement and left to interpretation as to what disturbances will require a generation report. If there is a concern from the Transmission Operator and they request information, PG&E can see including a requirement for generation to respond to a request for an evaluation concerning the response of the generator(s) to a disturbance.
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	Requirement R2 requires applicable entities to promptly analyze Bulk Electric System disturbances. There is no definition for the term promptly, and therefore the Requirement is vague.
Dana Wheelock	Seattle City Light	3	Approve	Requirement R2 requires applicable entities to promptly analyze Bulk Electric System disturbances. There is no definition for the term promptly, and therefore the Requirement is vague.
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Bethany	SMUD	5	Approve	

Voter	Entity	Segment	P 612	Comments
Wright				
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Eric Egge	Black Hills Corp	1	Disapprove	Requirements R2 and R3 require applicable entities to promptly analyze Bulk Electric System disturbances. There is no definition for the term promptly, and therefore the Requirement is vague.
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	see WECC comments
Rebecca Berdahl	Bonneville Power Administration	3	Approve	Should RRO be changed to RE ? What is 'promptly'? E.g., the Preliminary Disturbance form requires RC/BA/TOP/GOP/LSE to report within 1 day to NERC and RRO. Sometimes events are complicated and analysis takes time - no simple solution.
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Richard J. Mandes	Alabama Power Co.	3	Disapprove	Suggest removing the ‘At a minimum’ phrasing at the beginning of R3.1 as itdoes not add any clarity. We don’t believe the VSL being based on percentages isthe best approach. The number of reportable events will likely be small. Insteadof trying to construct one VSL, the VSLs for the entire standard should beundertaken at once. There should be a concern that generator operators, DP’sand LSEs may be unable to promptly analyze BES disturbances, particularlythose disturbances that may have originated outside of their systems, as theymay have neither the data nor the tools required for such analysis.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen	Southern Co. Services, Inc.	1	Disapprove	

Voter	Entity	Segment	P 612	Comments
Williamson				
Gregory Campoli	New York Independent System Operator	2	Disapprove	Taken in isolation the proposed change to R2 is appropriate. In the context of the entire requirement, the proposed changes to R2 and R3 are vague as written. The requirements mandate “prompt analysis”. FERC has requested NERC to avoid that kind of ambiguous phrase. The sub requirement R3.1 emasculates the main requirement by introducing “at a minimum”. From the FERC directive, it seems that only the sub requirement is needed and the main requirement should be deleted.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	Term: "promptly" is undefined and therefore would lead to inconsistent enforcement of requirement.
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Disapprove	The generator operators in WECC provide disturbance reports to WECC. The new requirement provides the information to TOP, BA, and RC. This standard requires far too many reports. Reports are sent to WECC, NERC, DOE and now the TOP and BA. It is not clear what benefit will be derived by this redundant requirement. The requirement should be limited to analyzing the events and providing reports upon request. WECC already has a disturbance reporting and analysis process to ensure BES issues are addressed. In addition the entities must analyze protection system operations in PRC-004.It is interesting that the COmmission continues to ensure unilateral communication among the entities by not requiring TOP and BA to share their disturbance reports with the GOP, DP, and LSE's.
Rex A Roehl	Indeck Energy Services, Inc.	5	Disapprove	The NERC glossary includes the term Reportable Disturbance. BES disturbance in R3.1 should be changed to Reportable Disturbance. Reportable event should not be used.
Terry L. Blackwell	Santee Cooper	1	Disapprove	The proposed changes do not appear to address the Commission’s directive. We suggest a new requirement should be “Following a disturbance and at the request of a RC, BA or TOP, a GO, DP or LSE shall promptly analyze the performance of their equipment and provide all requested information necessary to analyze BES disturbances.”
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	The proposed R3 for paragraph 612 should be dropped as it adds no value and does not improve reliability. Order 693 directed the ERO to consider this concern. The concern was considered and found to be adequately addressed in the existing R2 requirement. Analysis of disturbances on “its” system or facilities has not changed with the proposed revision. Therefore the proposed modifications do not enhance reliability. NERC can state that the FERC directive was reviewed and already addressed.

Voter	Entity	Segment	P 612	Comments
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	The requirement to provide the information to the Reliability Coordinator is not valid in the West, where the WECC RC has stated they do not want to deal with every registered entity. http://www.bpa.gov/corporate/business/reliability/Docs/2007/PNSC_RE_Data_Letter_2_070723.pdf.Although WECC has taken over the RC function, they continue to follow this policy.
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Disapprove	The same requirements for communicating affected entities during a disturbance should apply to all entities, not just a GOP, DP, and LSE. Not including a communication requirement for a TOP, RC, and BA does not ensure proper coordination and communication during an event that may affect the reliability of the BES.
Glen Reeves	Salt River Project	5	Disapprove	The term "disturbances" is not capitalized in the proposed requirement. Therefore, it is not the defined term used in the NERC Glossary. In addition, we recommend that proposed R3.1 be changed to read At a minimum, the responsible entity shall analyze the performance of their equipment. This information shall be provided to the responsible entity's associated Reliability Coordinator, Balancing Authority, and Transmission Operator at their request.
John T. Underhill	Salt River Project	3	Disapprove	The term "disturbances" is not capitalized in the proposed requirement. Therefore, it is not the defined term used in the NERC Glossary. In addition, we recommend that R 3.1 changed to read At a minimum, the responsible entity shall analyze the performance of their equipment. This information shall be provided to the responsible entity's associated Reliability Coordinator, Balancing Authority, and Transmission Operator at their request. There is no need to provide disturbance data to a Registered Entity if that entity does not require it.
Robert Kondziolka	Salt River Project	1	Disapprove	The term "disturbances" is not capitalized in the proposed requirement. Therefore, it is not the defined term used in the NERC Glossary. In addition, we recommend that proposed R3.1 be changed to read At a minimum, the responsible entity shall analyze the performance of their equipment. This information shall be provided to the responsible entity's associated Reliability Coordinator, Balancing Authority, and Transmission Operator at their request. There is no need to provide disturbance data to a Registered Entity if that entity does not require it.
Danny McDaniel	Cleco Power LLC	1	Disapprove	The term promptly in R2 & R3 is vague and a specific time frame should be specified. If a entity is in the middle of a hurricane or major ice storm, all resources are dedicated to the preservation and restoration of the BES.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Doug Bantam	LES	1	Disapprove	The word "promptly" is used within R2 and R3 but not R3.1. Recommend that the word

Voter	Entity	Segment	P 612	Comments
Dennis Florom	LES	5	Disapprove	"promptly" be deleted from these requirements. During any system disturbance the RC, BA or TOP will be focusing on mitigating the disturbance, then reporting of the disturbance (as outlined in the standard) and then start to investigate the cause of the disturbance. When promptly is used an entity may investigate prior to reporting which may lead to a non compliance situation.
Eric Ruskamp	LES	6	Disapprove	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Disapprove	
Edward P. Cox	AEP Marketing	6	Disapprove	There appears to be no benefit of having R3 and R3.1 as separate requirements. AEP suggests the two requirements be combined into one requirement as follows, "R3. Each Generator Operator, Distribution Provider, and Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities and provide this information to its associated Reliability Coordinator, Balancing Authority, and Transmission Operator.
Brock Ondayko	AEP Service Corp.	5	Disapprove	
Jerome Murray	Oregon Public Utility Commission	9	Approve	There is no definition for the term "promptly", and therefore the requirement is vague.
Daniel Herring	Detroit Edison Co.	4	Disapprove	There is no need for Distribution Providers to promptly analyze BES disturbances on its system or facilities operated below 100kV.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. RC and BA likely do not own much in the way of systems or facilities, except for back up facilities.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry.
Saurabh Saksena	National Grid	1	Disapprove	There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities.
Brian Evans-	Utility Services, Inc.	8	Disapprove	This proposal is not consistent with the efforts of the DSR SDT and should be directed to the team

Voter	Entity	Segment	P 612	Comments
Mongeon				to deal with this directive. The team's current discussions do not support the inclusion of these functional registrations as the understanding associated with LSE has changed since the point was first raised. LSEs do not necessarily own or operate physical assets and requiring them to conduct assessments is not necessary.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	We support the change for R2 as shown. It is suggested that R3 be revised to reads as shown below and that R3.1 be deleted. "R3. The Generator Operator, Distribution Provider and Load Serving Entity shall promptly analyze the performance of their equipment when impacted by a BES disturbance and make available information to a requesting Reliability Coordinator, Balancing Authority or Transmission Operator."If the change is accepted, conforming changes to the R3 VSLs are also needed.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Donald S. Watkins	Bonneville Power Administration	1	In Favor	
Francis J. Halpin	Bonneville Power Administration	5	In Favor	
Rebecca Berdahl	Bonneville Power Administration	3	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Gregg R Griffin	City of Green Cove Springs	3	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Bob Essex	Cowlitz County PUD	5	In Favor	
Russell A	Cowlitz County	3	In Favor	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Noble	PUD			
Rick Syring	Cowlitz County PUD	4	In Favor	
Robert W. Roddy	Dairyland Power Coop.	1	In Favor	
Daniel Herring	Detroit Edison Co.	4	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	In Favor	
George R. Bartlett	Entergy Corporation	1	In Favor	
Stanley M Jaskot	Entergy Corporation	5	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Greg Froehling	Green Country Energy	5	In Favor	
Kim Warren	IESO	2	In Favor	
Jim D. Cyrulewski	JDRJC Associates	8	In Favor	
Donald Gilbert	JEA	5	In Favor	
Walt Gill	Lake Worth Utilities	1	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	
Jason L Marshall	Midwest ISO, Inc.	2	In Favor	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	In Favor	
John Bos	Muscatine Power & Water	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Terry L Baker	Platte River Power Authority	3	In Favor	
John C. Collins	Platte River Power Authority	1	In Favor	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
Brenda L Truhe	PPL Electric Utilities Corp.	1	In Favor	
Mark A. Heimbach	PPL Generation LLC	5	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Laurie Williams	Public Service Co. of New Mexico	1	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
John T. Underhill	Salt River Project	3	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Daniel Baerman	San Diego G&E	5	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Dennis Sismaet	Seattle City Light	6	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	In Favor	
Bethany Wright	SMUD	5	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Mike Ramirez	SMUD	4	In Favor	
Tim Kelley	SMUD	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Richard McLeon	South Texas Electric Cooperative	1	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
Jeff Nelson	Springfield Utility Board	3	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
George T. Ballew	Tennessee Valley Authority	5	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
Brandy A Dunn	Western Area Power Administration	1	In Favor	
Louise McCarren	Western Electricity Coordinating Council	10	In Favor	
Linda Horn	Wisconsin Electric Power Co.	5	In Favor	
James R. Keller	Wisconsin Electric Power Marketing	3	In Favor	
Anthony Jankowski	Wisconsin Energy Corp.	4	In Favor	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Raj Rana	AEP	3	Opposed	
Edward P. Cox	AEP Marketing	6	Opposed	
Brock Ondayko	AEP Service Corp.	5	Opposed	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Brenda Powell	Constellation Energy Commodities Group	6	Opposed	
Robert Smith	Duke Energy	5	Opposed	
Walter Yeager	Duke Energy Carolina	6	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
Kevin Querry	FirstEnergy Solutions	3	Opposed	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
Gregory Campoli	New York Independent System Operator	2	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Bruce Glorvigen	OTP Wholesale Marketing	6	Opposed	
Tim	PowerSouth Energy	5	Opposed	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Hattaway	Cooperative			
Terry L. Blackwell	Santee Cooper	1	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	Because of our vote on R3 and its sub-requirement 3.1, we would vote No on the addition of the VSL for R3.
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Alan Gale	City of Tallahassee	5	Opposed	Disproportionately discriminates against enties that do not have a lot of disturbances.
Kevin Koloini	American Municipal Power -	4	Opposed	DP applicability should be removed

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
	Ohio			
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Generator Operators in ERCOT do not have the necessary data or applications necessary to properly analyze a disturbance on the system or facilities as stipulated. It is unclear on the VSL when they all basically require the "responsible entity failed to promptly analyze its disturbances on the BES" when a GOP does not have the capability to analyze the event as stated.GOPs can loose a facility that causes the disturbance. In that event, the GOP should be required to submit a complete disturbance report but not held accountable to perform analysis for which it is unable to provide.
Carolyn Ingersoll	Constellation Energy	3	Opposed	If the intent of including the reference to Attachment 1 in R4 was to assist in defining a Reportable Event the parenthesis should be directly after the phrase “reportable incident” and “reportable incident” should be changed to “Reportable Event”.
David A. Lapinski	Consumers Energy	3	Opposed	It is unclear as to what constitutes a disturbance. Does a disturbance, in the context of R2 and R3, constitutes a simple fault that is observable on the BES but normally cleared, or is it more limited. As written, these requirements could be interpreted to trigger thousands of “disturbance investigations” annually, the vast majority of which have no impact. Additionally, Attachment 2 (unchanged in this draft) purports to summarize OE-417 reporting requirements, but has a number of inaccuracies related to Attachment 2 timeliness requirements as compared to OE-417 reporting requirements (many of the elements with 1-hour reporting on Attachment 2 have 6-hour reporting on OE-417). It must be clarified whether Attachment 2 defines NERC requirements, or whether, for events described on OE-417, that OE-417 timeliness requirements govern. It should also be considered, relative to 1-hour reporting on Attachment 2, that, in the initial hour or two of an actual event, operating personnel will be fully engaged in determining the scope of the event and in addressing immediate operating concerns, and that they would be distracted from immediate reliability-related activities to prepare and file a report. Relative to R3 and the related VSL, “promptly” is a very subjective term, and is likely to lead to contention when evaluating compliance. Finally, there is unresolved duplication between this standard (Attachment 2, Incident No 5) and CIP-001 regarding sabotage incidents, and Attachment 2, Incident No 6 and CIP-008 regarding cyber incidents. We feel that the changes in this draft do not offer any improvement in the quality of this standard, and that, given the major problems with EOP-004-1, that the entire standard must be re-written, given due consideration to the inconsistencies with OE-417 and the inadvertent duplication with CIP-001 and CIP-006.
David Frank Ronk	Consumers Energy	4	Opposed	
James B Lewis	Consumers Energy	5	Opposed	
Brad Jones	Luminant Energy	6	Opposed	No opinion

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Steve Alexanderson	Central Lincoln PUD	3	Opposed	Opposed to R3 as written, therfore opposed to VRFs and VSLs.
Charles Locke	Kansas City Power & Light Co.	3	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
Michael Gammon	Kansas City Power & Light Co.	1	Opposed	
Guy Andrews	Georgia System Operations Corporation	4	Opposed	Refer to comments above.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	
Harold Taylor, II	GTC	1	Opposed	
Saurabh Saksena	National Grid	1	Opposed	
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	Taken in isolation the proposed change to R2 is appropriate. In the context of the entire requirement, the proposed changes to R2 and R3 are vague as written. The requirements mandate “prompt analysis”. FERC has requested NERC to avoid that kind of ambiguous phrase. The sub requirement R3.1 emasculates the main requirement by introducing “at a minimum”. From the FERC directive, it seems that only the sub requirement is needed and the main requirement should be deleted.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Opposed	The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry.
Daniel Duff	Liberty Electric Power LLC	5	Opposed	The percentages make no sense for a GO, who is unlikely to experience multiple disturbances, and therefore is automatically in severe violation space.
Martin Bauer	U.S. Bureau of	5	Opposed	The term "promptly" is not defined and should be clarified. This standard is not enforceable with this

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
P.E.	Reclamation			term undefined.
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	The VRF assignment of medium is appropriate. In regards to the VSLs conforming changes are needed per our requested R3 revisions. See our comment related to paragraph 612 (Q21).
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Mark Ringhausen	Old Dominion Electric Coop.	4	Opposed	The VRF is difficult to set... Lower or Medium would be my two choices, but I think the impact to the BES is not Real Time Operations as this is after the fact event analysis and should be in a long term horizon. Would recommend a Low VRF.VSLs are okay. Since most entities will only have one or two disturbances a year, the %s are difficult as most times any entity will always either be 100%, 50% or 0%. Consider changing to number of disturbance not analyized: 1,2,3...
Jonathan Appelbaum	United Illuminating Co.	1	Opposed	United Illuminating does not believe the VSL is properly descriptive. It lists the severity level based on a percentage of events not analyzed. What is the time period being considered? In a calendar year, in a three year audit period?
Ajay Garg	Hydro One Networks, Inc.	1	Opposed	VRFs and VSLs should not be added on a selective basis, i.e. only to some requirements. They should be added to every requirement.
Michael D. Penstone	Hydro One Networks, Inc.	3	Opposed	
William D Shultz	Southern Co. Generation	5	In Favor	VSL: the completeness of evaluations is a reasonable measure of the severity level of non-compliance.VRF: An event may not always have a moderate impact on reliability, indicating that a Lower VRF be assigned. This appears to not be allowed in the five tier classification system: Examples of lower risk violations may include - Failure to provide data or documents (excludes data needed for real-time operations) within a specified date.
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Opposed	VSLs for an RC, BA, and TOP need to be included.
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P615:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 615	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	American Public Power Association	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Danny McDaniel	Cleco Power LLC	1	Abstain	
Bryan Y Harper	Cleco Utility Group	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Robert Smith	Duke Energy	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Luther E. Fair	Gainesville	1	Abstain	

Voter	Entity	Segment	P 615	Comments
	Regional Utilities			
Ajay Garg	Hydro One Networks, Inc.	1	Abstain	
Michael D. Penstone	Hydro One Networks, Inc.	3	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Tim Hattaway	PowerSouth Energy Cooperative	5	Abstain	
Laurie Williams	Public Service Co. of New Mexico	1	Abstain	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Jason L.	AESO	2	Approve	

Voter	Entity	Segment	P 615	Comments
Murray				
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Nickesha P Carrol	ConEd of NY	6	Approve	

Voter	Entity	Segment	P 615	Comments
Christopher L de Graffenried	ConEd of NY	1	Approve	
Wilket (Jack) Ng	ConEd of NY	5	Approve	
Peter T Yost	ConEd of NY	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	

Voter	Entity	Segment	P 615	Comments
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	
Kenneth Dresner	FirstEnergy Solutions	5	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	
Dennis Minton	Florida Keys Electric	1	Approve	

Voter	Entity	Segment	P 615	Comments
	Cooperative Assoc.			
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas E Washburn	FMPP	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Greg Froehling	Green Country Energy	5	Approve	
Harold Taylor, II	GTC	1	Approve	
Kim Warren	IESO	2	Approve	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Approve	
Donald Gilbert	JEA	5	Approve	
Charles Locke	Kansas City Power & Light Co.	3	Approve	
Michael Gammon	Kansas City Power & Light Co.	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	

Voter	Entity	Segment	P 615	Comments
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Brad Jones	Luminant Energy	6	Approve	
Mike Laney	Luminant Generation Co. LLC	5	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Douglas	Ohio Edison Co.	4	Approve	

Voter	Entity	Segment	P 615	Comments
Hohlbaugh				
Robert Mattey	Ohio Valley Electric Corp.	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C.	Platte River Power	1	Approve	

Voter	Entity	Segment	P 615	Comments
Collins	Authority			
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	

Voter	Entity	Segment	P 615	Comments
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Daniel Baerman	San Diego G&E	5	Approve	
Scott Peterson	San Diego G&E	3	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	

Voter	Entity	Segment	P 615	Comments
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
William D Shultz	Southern Co. Generation	5	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise	Western Electricity	10	Approve	

Voter	Entity	Segment	P 615	Comments
McCarren	Coordinating Council			
Linda Horn	Wisconsin Electric Power Co.	5	Approve	
James R. Keller	Wisconsin Electric Power Marketing	3	Approve	
Anthony Jankowski	Wisconsin Energy Corp.	4	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Paul Rocha	CenterPoint Energy	1	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Carolyn Ingersoll	Constellation Energy	3	Disapprove	
Brenda Powell	Constellation Energy Commodities Group	6	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Dan Roethemeyer	Dynegy Inc.	5	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie	Louisville Gas and	5	Disapprove	

Voter	Entity	Segment	P 615	Comments
Martin	Electric Co.			
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V.	Tri-State G & T	1	Disapprove	

Voter	Entity	Segment	P 615	Comments
Carman	Association Inc.			
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. 2. These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. 3. The RC and BA, responsible for analysis, most likely do not own much in the way of systems or facilities except for back-up facilities. The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 4. The new standard language in R3 and 3.1 suggests that any disturbance originating from outside of the applicable Registered Entity will have to be reported and there are no means for how the reporting is to be handled. 5. Why wasn't DP added to R4?
Kirit S. Shah	Ameren Services	1	Disapprove	A.5. Effective date - Most entities revise procedures on an annual basis. having an effective date that is less than a year away might result incremental, hastily developed procedures. If the effective date was the first day of the first calendar year after approval, it is likely no extra reviews/update would be necessary.
Mark Ringhausen	Old Dominion Electric Coop.	4	Approve	Agree with the NERC comments.
Rex A Roehl	Indeck Energy Services, Inc.	5	Disapprove	As to Paragraph 615, the VSL for R3 presumes numerous disturbances. Neither a GOP nor an LSE is likely to see more than a few. Missing one of six would be a Severe violation, whereas in R2, an RC, BA or TOP could miss 25% of hundreds of disturbances and be a Lower violation. The VSL is misapplied to GOP and LSE. All disturbances are not equivalent. Missing one disturbance which foretold or was a precursor to the big one is much more significant than missing a common one. The VSL needs to assess the reliability significance of the violation.
Gregg R	City of Green Cove	3	Disapprove	attachement 1 needs to be modified to define which functional entity needs to report which

Voter	Entity	Segment	P 615	Comments
Griffin	Springs			reportable event.
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Kevin Koloini	American Municipal Power - Ohio	4	Disapprove	DP applicability should be removed
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	I don't believe events that result in "1d. Identification of non-compliance with NERC standards" should require a disturbance report. Entities are required to self report any potential violations of standards whether they are apart of a disturbance or not
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	Need to define which Functional Entities are responsible for each type of possible "reportable event" in Attachment 1.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	Not low hanging fruit.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
Saurabh Saksena	National Grid	1	Disapprove	o There is inconsistency in requirements R3 and R4 with respect to "Distribution Provider". R3 includes DP while R4 does not. National Grid suggests including Distribution Provider in R4. o Who is responsible for reporting when DP is analyzing the disturbances? National Grid suggests that DP should be listed in Attachment 1.
Raj Rana	AEP	3	Disapprove	R4 needs to include the Distribution Provider since it was added to R3. The VSL for the proposed R3 is not consistent in severity with the existing VSL for R2. Under the current standard, each Generator Operator and Load Serving Entity is required to promptly analyze BES disturbances per R2 and its
Edward P. Cox	AEP Marketing	6	Disapprove	

Voter	Entity	Segment	P 615	Comments
Brock Ondayko	AEP Service Corp.	5	Disapprove	associated VSL. The proposed standard moves the GOP and LSE requirements to a new requirement, R3. A VSL was established for R3, but the VSL for R2 was not revised. Per the proposed standard, failure of the Generator Operator to promptly analyze greater than 15% of its disturbances on the BES would result in a Severe VSL. However, using the existing R2 VSL, a Transmission Operator who fails to promptly review 1% to 25% of its disturbances on the BES would only be subjected to a Moderate VSL. The VSLs should be revised to allow for consistency between the R2 and R3 VSLs, and correspond with what has already been established for the TOP. Additionally the VSL for R2 in the current standard should be revised to remove reference to the Generator Operator.The last sentence of Measures M2 and M3 each need to be revised to reference Requirements 4.1 and 4.3, respectively.
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	See BPA comments
Francis J. Halpin	Bonneville Power Administration	5	Approve	Should RRO be changed to RE ? What is promptly? The Preliminary Disturbance form requires RC/BA/TOP/GOP/LSE to report within 1 day to NERC and RRO. Sometimes events are complicated and analysis takes time - no simple solution.
Randall McCamish	City of Vero Beach	1	Disapprove	The changes made to the standard do not address the concern: "Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations." Attachment 1 should be modified to define which Functional Entity needs to report which reportable event. It is still quite ambiguous who has to report what. For instance, a Distribution Provider would certainly not have to report an islanding event, yet, it is possible to interpret it that way.
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Disapprove	The changes proposed by NERC do not address the concerns of Xcel in regards to clearly defining what a reportable event is.
Alan Gale	City of Tallahassee	5	Disapprove	The clarifier (as shown in Attachment 1) should be after "...LSE experiencing a reportable incident..." if this is to be resposnsive to FERC paragraph 615. The WECC process cannot be more lax than the NERC Standard. Teh WECC procedure would have to be modified to meet the NERC Standard, or they could apply for a variance.

Voter	Entity	Segment	P 615	Comments
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Disapprove	The development of a final report does not take into account the entities internal process. It is suggested that a preliminary report be made available within 60 days.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	The new standard language in R3 and 3.1 suggests that any disturbance originating from outside of the applicable Registered Entity will have to be reported and there are no means for how the reporting is to be handled. Why wasn't DP added to R4?
Gregory Campoli	New York Independent System Operator	2	Disapprove	The proposed change to the definition of “Reportable Event” is in direct competition with the Event Analysis Working Group’s initiative to define Event Categories. That initiative is posted for comments.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	
Charles H Yeung	Southwest Power Pool	2	Disapprove	
Brian Evans-Mongeon	Utility Services, Inc.	8	Disapprove	The proposed language does not clarify reportable events and should be directed to the DSR SDT.
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	The requirement to provide the information to the Reliability Coordinator is not valid in the West, where the WECC RC has stated they do not want to deal with every registered entity. http://www.bpa.gov/corporate/business/reliability/Docs/2007/PNSC_RE_Data_Letter_2_070723.pdf .Although WECC has taken over the RC function, they continue to follow this policy.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	There is the addition of Distribution Provider and retention of LSE. If we are going to start adding owners of system/facilities to the applicability section, why not GO and TO? There is no need to retain LSE as it does not have a physical system or facilities. These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team. The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry.
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	United Illuminating does not believe the VSL is properly descriptive. It lists the severity level based on a percentage of events not analyzed. What is the time period being considered? In a calendar year, in a three year audit period?
Jason L	Midwest ISO, Inc.	2	Disapprove	We suggest the parenthesis within the requirement should be removed from around the reference

Voter	Entity	Segment	P 615	Comments
Marshall				to the attachment. We don't believe that the changes address Xcel's concern expressed in the directive. We believe Xcel wanted more details for the specific functional entities. Furthermore, the directive did not state that the Commission believed that Xcel's concerns regarding the WECC process should be handled through a variance as stated in NERC's comments. As a result, we do not believe the directives in paragraph 615 are fully addressed. Adding sub-requirement 3.1 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.

Summary Consideration for changes related to P693:

Some entities suggested that references to TPL-001-, -002, and -003 were assigning responsibilities to entities other than those included in TPL-001, -002, and -003. The Response Team believes that although the standard references another standard, such a reference can expand the applicability of the other standard. Entities should review the referenced standard, and if it is applicable to them, ensure they are meeting it.

Some entities expressed a more general concern that the standard needs significant rewriting and improvement. The team responded that such large changes are outside the scope of this project.

Voter	Entity	Segment	P 693	Comments
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	

Voter	Entity	Segment	P 693	Comments
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Randi Woodward	Minnesota Power, Inc.	1	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Tim Hattaway	PowerSouth Energy Cooperative	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Jeff Nelson	Springfield Utility Board	3	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Raj Rana	AEP	3	Approve	
Edward P.	AEP Marketing	6	Approve	

Voter	Entity	Segment	P 693	Comments
Cox				
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kirit S. Shah	Ameren Services	1	Approve	
Mark Peters	Ameren Services	3	Approve	
Sam Dwyer	Amerenue	5	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
Jason Shaver	ATC	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	

Voter	Entity	Segment	P 693	Comments
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
Brian Conroy	Central Maine Power Co.	1	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Danny McDaniel	Cleco Power LLC	1	Approve	
Bryan Y Harper	Cleco Utility Group	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Approve	
Nickesha P Carrol	ConEd of NY	6	Approve	

Voter	Entity	Segment	P 693	Comments
Christopher L de Graffenried	ConEd of NY	1	Approve	
Wilket (Jack) Ng	ConEd of NY	5	Approve	
Peter T Yost	ConEd of NY	3	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
Brenda Powell	Constellation Energy Commodities Group	6	Approve	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion	5	Approve	

Voter	Entity	Segment	P 693	Comments
	Resources, Inc.			
John K Loftis	Dominion Virginia Power	1	Approve	
Robert Smith	Duke Energy	5	Approve	
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
Dan Roethemeyer	Dynegy Inc.	5	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	
Kenneth Dresner	FirstEnergy Solutions	5	Approve	

Voter	Entity	Segment	P 693	Comments
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Greg Froehling	Green Country Energy	5	Approve	
Harold Taylor, II	GTC	1	Approve	
Ajay Garg	Hydro One Networks, Inc.	1	Approve	
Michael D.	Hydro One	3	Approve	

Voter	Entity	Segment	P 693	Comments
Penstone	Networks, Inc.			
Kim Warren	IESO	2	Approve	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Approve	
Kathleen Goodman	ISO New England, Inc.	2	Approve	
Donald Gilbert	JEA	5	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Approve	
Charlie Martin	Louisville Gas and Electric Co.	5	Approve	
Daryn Barker	Louisville Gas and Electric Co.	6	Approve	
Brad Jones	Luminant Energy	6	Approve	
Mike Laney	Luminant Generation Co. LLC	5	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	

Voter	Entity	Segment	P 693	Comments
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
Saurabh Saksena	National Grid	1	Approve	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Approve	
David H. Boguslawski	Northeast Utilities	1	Approve	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power	4	Approve	

Voter	Entity	Segment	P 693	Comments
	Authority			
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Brenda L	PPL Electric Utilities	1	Approve	

Voter	Entity	Segment	P 693	Comments
Truhe	Corp.			
Mark A. Heimbach	PPL Generation LLC	5	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	

Voter	Entity	Segment	P 693	Comments
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Scott Peterson	San Diego G&E	3	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Bethany Wright	SMUD	5	Approve	

Voter	Entity	Segment	P 693	Comments
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
William D Shultz	Southern Co. Generation	5	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
John Tolo	Tucson Electric	1	Approve	

Voter	Entity	Segment	P 693	Comments
	Power Co.			
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
James A Ziebarth	Y-W Electric Association, Inc.	4	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L	Xcel Energy, Inc.	1	Disapprove	

Voter	Entity	Segment	P 693	Comments
Pieper				
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Rex A Roehl	Indeck Energy Services, Inc.	5	Disapprove	A GO cannot coordinate the TP analysis on new facilities. The LGIP controls. The GO should not be responsible for the assessments made by TP's. Remove the GO from FAC-002. Response: Although the standard references another standard, the Response Team does not believe such a reference can expand the applicability of the other standard. Entities should review the referenced standard, and if it is applicable to them, ensure they are meeting it.
Michael T. Quinn	Oncor Electric Delivery	1	Disapprove	FAC-002 currently only requires that the Steady State, Short Circuit and Stability Studies be performed to comply with TPL-001. By including TPL-002 and TPL-003 NERC is greatly increasing the scope, time and cost of the analysis required for a future entity that may never interconnect to the bulk power system. Response: The Response Team believes this change adequately addresses the Commission directive. Concerns with the validity of the directive should be addressed with the Commission.
Charles H Yeung	Southwest Power Pool	2	Disapprove	In the context of the entire requirement, the proposed change raises an issue that make this seemingly trivial request more complex than the requestor makes it out to be. o The proposed change is a change to a sub requirement to R1. However, R1 is not well designed as a mandatory standard. R1 includes multiple applicable entities, and requires that those entities all "coordinate and cooperate". The latter terms are not defined, not measured and confusing as it applies to compliance. Response: Improving these terms and reducing any associated ambiguity is a valid goal, but outside of the scope of this particular project. We encourage entities to pursue those improvements through other projects.
David A. Lapinski	Consumers Energy	3	Disapprove	Of the six applicable entities on FAC-002, only two are applicable entities under the TPL standards (Transmission Planner and Planning Authority/Coordinator, depending on the Functional Model terminology). The reference to the TPL standards in R1.4, which addresses ONLY the other four entities, makes those entities indirectly subject to the TPL standards, which are irrelevant to those entities. Response: Although the standard references another standard, the Response Team does not believe such a reference can expand the applicability of the other standard. Entities should review the referenced standard, and if it is applicable to them, ensure they are meeting it.

Voter	Entity	Segment	P 693	Comments
David Frank Ronk	Consumers Energy	4	Disapprove	Of the six applicable entities on FAC-002, only two are applicable entities under the TPL standards (Transmission Planner and Planning Authority/Coordinator, depending on the Functional Model terminology). The reference to the TPL standards in R1.4, which addresses ONLY the other four entities, makes those entities indirectly subject to the TPL standards, which are irrelevant to those entities. Response: Although the standard references another standard, the Response Team does not believe such a reference can expand the applicability of the other standard. Entities should review the referenced standard, and if it is applicable to them, ensure they are meeting it.
James B Lewis	Consumers Energy	5	Disapprove	
Mark Ringhausen	Old Dominion Electric Coop.	4	Disapprove	Seems like this change should be in the TPL standards as you could read this to require the GO, TO, DP and LSE to perform this assessment. Certainly, these entities do not have the necessary capabilities to perform normal or contigency studies. I do agree that this analysis must be performd by the TP/PA.When ODEC requests a new load interconnection (as a DP/LSE) from one of our transmission providers, we provide the requested data for the analysis, but we never see the study results nor do we have access to them. M2 syas we must provide evidence of assessment of the reliability impact, but we do not have this information, our transmission providers retain it. Response: Although the standard references another standard, the Response Team does not believe such a reference can expand the applicability of the other standard. Entities should review the referenced standard, and if it is applicable to them, ensure they are meeting it.
Gregory Campoli	New York Independent System Operator	2	Disapprove	Taken in isolation the proposed change to R2 is appropriate. In the context of the entire requirement, the proposed change raises an issue that make this seemingly trivial request more complex than the requestor makes it out to be. o The proposed change is a change to a sub requirement to R1. However, R1 is not well designed as a mandatory standard. R1 includes multiple applicable entities, and requires that those entities all “coordinate and cooperate”. The latter terms are not defined, not measured and confusing as it applies to compliance. Response: Improving these terms and reducing any associated ambiguity is a valid goal, but outside of the scope of this particular project. We encourage entities to pursue those improvements through other projects.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	
Richard J. Mandes	Alabama Power Co.	3	Approve	The Commission did not request the clause to be added but only requestedthe reference to TPL-001, TPL-002 and TPL-003 to be added “to requireevaluation of system performance under both normal and contingency conditionsby referencing TPL-001 through TPL-003.” Response: We do not believe the use of this phrase causes any problems, and none have been
Anthony L Wilson	Georgia Power Co.	3	Approve	

Voter	Entity	Segment	P 693	Comments
Gwen S Frazier	Gulf Power Co.	3	Approve	identified in the comment.
Don Horsley	Mississippi Power	3	Approve	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Approve	
Daniel Prowse	Manitoba Hydro	6	Disapprove	The proposed addition to R1.4 appears redundant and could conflict with the TPL requirements. That is; adding the words “under both normal and contingency conditions” is unnecessary since”TPL-001-0, TPL-002-0, and TPL-003-0” already require analysis of normal and contingency conditions. The Oder only requested that the TPL standards be referenced. Also, there are TPL-001-0.1, TPL-002-0 and TPL-002-0a, TPL-003-0 and TPL-003-0a in the NERC posting of existing standards, so which TPL version is intended to be used? Response: We do not believe the use of this phrase causes any problems, and none have been identified in the comment. Regarding the appropriate version of the TPL standard to use, the versions referenced include errata changes or interpretations to the standard; there have been no material changes to the content of the standards. As such, it is appropriate to use the corrected or interpreted versions of the referenced standards.
Greg C Parent	Manitoba Hydro	3	Disapprove	
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Disapprove	The requirement cites TPL-001 through 003 which do not apply to GO's. The modification makes matters worse in that the GO is now required to analyze system performance under contigency conditions. This is normally performed by the TP. Response: Although the standard references another standard, the Response Team does not believe such a reference can expand the applicability of the other standard. Entities should review the referenced standard, and if it is applicable to them, ensure they are meeting it.
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	The Violation Severity Levels for R1.4 do not reflect the additional references to Standards TPL-002-0 and TPL-003-0 as included in the proposed change for R1.4. Response: The current VSL, which reads “The responsible entity's assessment did not include the evidence of the studies,” seems sufficiently broad so as to include the additional references added.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We believe “under normal and emergency contingency conditions” should be struck from the additions. TPL-001, TPL-002 and TPL-003 already identify normal and emergency conditions through the Table C requirements. We believe the clause only adds confusion. Furthermore, the Commission

Voter	Entity	Segment	P 693	Comments
				did not request the clause to be added but requested the reference to TPL-001, TPL-002 and TPL-003 to be added "to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003." Response: We do not believe the use of this phrase causes any problems, and none have been specifically identified in the comment.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	We believe "under normal and emergency contingency conditions" should be struck from the additions. TPL-001, TPL-002 and TPL-003 already identify normal and emergency conditions through the Table C requirements. We believe the clause only adds confusion. Response: We do not believe the use of this phrase causes any problems, and none have been specifically identified in the comment.
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	Why not replace RRO with RE throughout?, otherwise this looks reasonable with regard to the order. Response: Only those standards associated with Directives were included in this effort; accordingly, there have only been changes in these standards.

Summary Consideration for changes related to P1249:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1249	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	American Public Power Association	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Linda R. Jacobson	City of Farmington	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	

Voter	Entity	Segment	P 1249	Comments
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald	PECO Energy	1	Abstain	

Voter	Entity	Segment	P 1249	Comments
Schloendorn				
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Randall McCamish	City of Vero Beach	1	Approve	

Voter	Entity	Segment	P 1249	Comments
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Charles Locke	Kansas City Power & Light Co.	3	Approve	
Michael Gammon	Kansas City Power & Light Co.	1	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	

Voter	Entity	Segment	P 1249	Comments
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Steven Grego	MEAG Power	3	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	

Voter	Entity	Segment	P 1249	Comments
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J.	RRI Energy	5	Approve	

Voter	Entity	Segment	P 1249	Comments
Bradish				
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
David F. Lemmons	Xcel Energy, Inc.	6	Approve	
Gregory L Pieper	Xcel Energy, Inc.	1	Approve	
Liam Noailles	Xcel Energy, Inc.	5	Approve	
Rodney Phillips	Allegheny Power	1	Disapprove	
Bob Reeping	Allegheny Power	3	Disapprove	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	

Voter	Entity	Segment	P 1249	Comments
Donald S. Watkins	Bonneville Power Administration	1	Disapprove	
Francis J. Halpin	Bonneville Power Administration	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Daniel Herring	Detroit Edison Co.	4	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S	FirstEnergy	6	Disapprove	

Voter	Entity	Segment	P 1249	Comments
Travaglianti	Solutions			
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
John Bos	Muscatine Power & Water	3	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W	South Mississippi	5	Disapprove	

Voter	Entity	Segment	P 1249	Comments
Johnson	Electric Power Association			
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Raj Rana	AEP	3	Disapprove	: Paragraphs 1249 & 1250: The proposed change in MOD-017 R1.1, "for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year" does not support reliability for the following reasons:1. It is unclear what reliability objective is being served. If this data is for NERC to analyze and verify peak load data used by Registered Entities for operations, then the weather across Registered Entities varies too greatly to provide one set of coincident numbers and would provide little benefit. What reliability benefit would there be to add a requirement for sending information that will not be used? This would be an inefficient use of resources, which could instead be used for supporting other reliability objectives.2. Whether or not the load data is sensitive to weather is a matter of importance for the local planners, but not for planners who report wide-area assessments to NERC.3. NERC through its Rules of Procedure has the ability to collect the information when necessary.
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. General comment - In the "NERC Comments" section, remove the "Section B" descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. General comment - Each entity's expertise should be relied upon to gather the appropriate weather information.4. In Requirement R1.5 - What is meant by "biasing of each load forecast"?5. With respect to Requirement R1.5 - Is this applicable to Demand Response?6. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 7. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 8. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.

Voter	Entity	Segment	P 1249	Comments
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	a) MOD-017 R1. It is not clear what temperature and humidity data to use. We believe this data collection would actually serve to confuse rather than enhance reliability. If the requirement remains, recommend removing the "if" clause and simply stating to supply temperature and humidity data.b) MOD-017 R2. It is not clear when an entity is required to modify its load forecast assumptions. The use of the abbreviation e.g. (which means "for example") implies that there are other situations which would require modification of the forecast assumptions, but we are given no guidance as to what they might be. The 10% seems to be an arbitrary value as well. Utilities, as good business practice, seek to have the best forecast possible and its inherent to their own interests to either improve their process or replace the model as needed. We recommend the requirement should be rewritten as follows:c) The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall annually review its Load forecast process to improve accuracy as necessary.d) Otherwise, if there are other conditions that would require that assumptions be modified those conditions must be clearly stated in the standard. Entities have a right to a clear statement of what they are required to do and when they are required to do it. Sometimes assumptions are correct, and extreme conditions occur. It does not necessitate that your assumptions should change for the next year.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	Addition of responsible entities is not low hanging fruit. The issue should be addressed by a SDT.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	All referenced requirements need to explicitely address DSM, or the effect of DSM, on the forecast. The drafting team should clearly define how DSM should be considered, that is as an interruptible load or as a resource.
Alan Gale	City of Tallahassee	5	Approve	Although which temperature should we use if our territory is large? Especially with a large North-South axis.
Daniel Prowse	Manitoba Hydro	6	Disapprove	Asking for temperature is okay. But we do not use humidity in our monthly modeling and do not maintain that data. Would agree with changes if they said "temperature and any other weather variables used for weather normalization".
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Mel Jensen	APS	5	Disapprove	AZPS does not agree with how NERC has revised the standard to comply with Order 693. Our reading is the FERC is requesting temperature and humidity readings for the peak load, interpreted as Peak Day. The Standard as proposed is over-reaching as it requires weather data for each and every hour
Robert D	Arizona Public	1	Disapprove	

Voter	Entity	Segment	P 1249	Comments
Smith	Service Co.			of every day (8760).
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
David Murray	PSEG Power LLC	5	Approve	Comments: While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Bob Essex	Cowlitz County PUD	5	Approve	Cowlitz votes affirmative under protest to preserve the greater good of the ANSI standard development process. The FERC Order does not adequately address true reliability concerns nor give due weight to the technical expertise of the ERO; the FERC unlawfully substitutes its own expertise. Weather data is already available from NOAA and other organizations for thousands of locations throughout the US. Requiring utilities provide this data in addition is duplicative and unnecessary and distracts utility staff from engaging in work that could improve forecasting and reliability.
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Bethany Wright	SMUD	5	Disapprove	Disapprove changes for directives in Paragraphs 1249 and 1250. Comment: Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 because it is redundant. We recommend an alternative to actually submitting the coincident hourly temperature and humidity data that requires the applicable entity to be able to demonstrate that they record and consider coincident hourly temperature and humidity data when developing forecasts.
James Leigh-Kendall	SMUD	3	Disapprove	
Mike Ramirez	SMUD	4	Disapprove	
Tim Kelley	SMUD	1	Disapprove	
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE defers to and supports its RTO organizations (PJM and MISO) regarding the proposed load forecasting changes.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	

Voter	Entity	Segment	P 1249	Comments
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	For an entity that covers a diverse area, it is unclear where the temperature and humidity readings are to be taken, or if many (how many?) readings are to be averaged. And why does the entity that has a variation on temperature but not humidity, still need to report humidity?
Danny McDaniel	Cleco Power LLC	1	Disapprove	For an entity that covers a diverse area, it is unclear where the temperature and humidity readings are to be taken, or how many readings are required. Also, we provide such data, hourly demands, to SPP per their form. The change would require a change in the submittal form. The rest of the data is submitted in EIA-411. Will EIA-411 form be revised to accommodate this new information?
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	In R1.1 and R1.2 the terminology "loads that vary based on temperature and /or humidity" needs further clarification, i.e. specifically define weather sensitive loads. R1.5 is out of place here, this pertains to day ahead forecasting while the rest of MOD 17 addresses the long term forecast.
Saurabh Saksena	National Grid	1	Disapprove	In requirement R1.1, the location of the reading for coincident hourly temperature and humidity is not clear. Also, in National Grid, the record keeping is done on aggregate basis and not on daily basis. The data is taken from weather services and it is not an automatic process of data collection.
Brenda S. Anderson	Bonneville Power Administration	6	Disapprove	In the directives in Paragraph 1250 Alcoa's proposal was rejected because it appears to provide a broad exemption to the Reliability Standard due to the subjective nature of determining whether a load varies with temperature and/or humidity. Regardless of the variability of load with these weather elements, providing the weather data with the loads allows all who are trying to assess or validate past events and databases with the data to make sound mathematical or statistical determinations. Not having the data does not ensure this capability which is the purpose of the Standard. Thus the words "that vary" should be removed from Requirement R1.1. Further, entities do not want to be penalized for not being able to provide the data from a weather station that is near the load if it is not available, nor do entities want to establish weather capturing capabilities. Thus, Requirement R1.1. should be changed to read something like "Integrated hourly demands in megawatts(MW) for the prior year along with coincident hourly temperature from weather station(s) in proximity to the load center(s) and if available hourly humidity from the same weather stations." Because monthly loads may experience heating and cooling impacts in the same month, using monthly temperature is not the best method to approach analyzing temperature impacts on monthly date. Further, by having already provided hourly weather data in Requirement 1.1 make the request for the monthly temperature data in Requirement 1.2 redundant and really worthless. Typically, the monthly analysis of energy and temperature is done using Heating and Cooling Degree Days(HDD/CDD). Any analyst should be able to calculate the necessary HDD and or CDD using the hourly data provided in Requirement 1.1 for the analysis. Requirement 1.2 should be changed to read
Rebecca Berdahl	Bonneville Power Administration	3	Disapprove	

Voter	Entity	Segment	P 1249	Comments
				something similar to this "Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. If hourly temperatures were not provided in Requirement 1.1 provide Heating and Cooling degree days base 65, and humidity data for the prior year from weather station(s) in proximity to the load center(s)".
Dana Wheelock	Seattle City Light	3	Disapprove	In the directives in Paragraph 1250 Alcoa's proposal was rejected because it appears to provide a broad exemption to the Reliability Standard due to the subjective nature of determining whether a load varies with temperature and/or humidity. Regardless of the variability of load with these weather elements, providing the weather data with the loads allows all who are trying to assess or validate past events and databases with the data to make sound mathematical or statistical determinations. Not having the data does not ensure this capability which is the purpose of the Standard. Thus the words "that vary" should be removed from Requirement R1.1. Further, entities do not want to be penalized for not being able to provide the data from a weather station that is near the load if it is not available, nor do entities want to establish weather capturing capabilities. Thus, Requirement R1.1. should be changed to read something like "Integrated hourly demands in megawatts(MW) for the prior year along with coincident hourly temperature from weather station(s) in proximity to the load center(s) and if available hourly humidity from the same weather stations." Because monthly loads may experience heating and cooling impacts in the same month, using monthly temperature is not the best method to approach analyzing temperature impacts on monthly date. Further, by having already provided hourly weather data in Requirement 1.1 make the request for the monthly temperature data in Requirement 1.2 redundant and really worthless. Typically, the monthly analysis of energy and temperature is done using Heating and Cooling Degree Days(HDD/CDD). Any analyst should be able to calculate the necessary HDD and or CDD using the hourly data provided in Requirement 1.1 for the analysis. Requirement 1.2 should be changed to read something similar to this "Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. If hourly temperatures were not provided in Requirement 1.1 provide Heating and Cooling degree days base 65, and humidity data for the prior year from weather station(s) in proximity to the load center(s)".
Dennis Sismaet	Seattle City Light	6	Disapprove	
Hao Li	Seattle City Light	4	Disapprove	
Pawel Krupa	Seattle City Light	1	Disapprove	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	ISO-NE is the logical entity to provide this information rather than the LSE.
Donald Gilbert	JEA	5	Disapprove	JEA can comply with this if necessary and I understand that one must make a determination of load sensitivity to natural weather conditions, but JEA has found that humidity as a variable does not

Voter	Entity	Segment	P 1249	Comments
				correlate well to actual load demands and sometimes can have a negative correlation especially if precipitation is involved causing a high humidity reading, but lower loads. JEA has implemented a regression analysis that filters out the affects of high humidity/precipitation to focus on the higher loads that occur with higher temperatures that are area wide and not affected by cloud cover and precipitation normally occuring with high humidity.
Terry L Baker	Platte River Power Authority	3	Disapprove	Loads not only vary based upon temperature and/or humidity, but sunshine index as well. The economy has also played a big role in forecast inaccuracies.
John C. Collins	Platte River Power Authority	1	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	MOD-017 R1. It is not clear what temperature and humidity data to use. We believe this data collection would actually serve to confuse rather than enhance reliability. If the requirement remains, recommend removing the “if” clause and simply stating to supply temperature and humidity data.MOD-017 R2. It is not clear when an entity is required to modify its load forecast assumptions. The use of the abbreviation e.g. (which means “for example”) implies that there are other situations which would require modification of the forecast assumptions, but we are given no guidance as to what they might be. The 10% seems to be an arbitrary value as well. Utilities, as good business practice, seek to have the best forecast possible and its inherent to their own interests to either improve their process or replace the model as needed. We recommend the requirement should be rewritten as follows:The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall annually review its Load forecast process to improve accuracy as necessary.Otherwise, if there are other conditions that would require that assumptions be modified those conditions must be clearly stated in the standard. Entities have a right to a clear statement of what they are required to do and when they are required to do it. Sometimes assumptions are correct, and extreme conditions occur. It does not necessitate that your assumptions should change for the next year.
Greg C Parent	Manitoba Hydro	3	Disapprove	o Paragraph 1249: Asking for temperature is okay. But we do not use humidity in our monthly modeling and do not maintain that data. Would agree with changes if they said "temperature and any other weather variables used for weather normalization".
Edward P. Cox	AEP Marketing	6	Disapprove	Paragraphs 1249 & 1250: The proposed change in MOD-017 R1.1, “for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year” does not support reliability for the following reasons:1. It is unclear what reliability objective is being served. If this data is for NERC to analyze and verify peak load data used by Registered Entities for operations, then the weather across Registered Entities varies too greatly to provide one set of
Brock Ondayko	AEP Service Corp.	5	Disapprove	

Voter	Entity	Segment	P 1249	Comments
				coincident numbers and would provide little benefit. What reliability benefit would there be to add a requirement for sending information that will not be used? This would be an inefficient use of resources, which could instead be used for supporting other reliability objectives.2. Whether or not the load data is sensitive to weather is a matter of importance for the local planners, but not for planners who report wide-area assessments to NERC.3. NERC through its Rules of Procedure has the ability to collect the information when necessary
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraphs 1249 and 1250 - While we could report both hourly temperature and humidity for the prior year, we don't use humidity for either the forecast or weather normalization, so we would like to have language that makes it an option to be used in the forecasting process, particularly if our forecast meets the accuracy requirement.
Michael F Gildea	Dominion Resources Services	3	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. Some examples are cited below: 1. We do not agree that addition of the Transmission Planner, in and of itself, improves or enhances reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. 2. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models. 3. R2, as written, could decrease reliability by allowing a wider bandwidth before action iscurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. 4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop

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				appropriately.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. Some examples are cited below:1. We do not agree that addition of the Transmission Planner, in and of itself, improves or enhances reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.2. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models.3. R2, as written, could decrease reliability by allowing a wider bandwidth before action iscurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
John K Loftis	Dominion Virginia Power	1	Disapprove	
George R. Bartlett	Entergy Corporation	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and
Stanley M Jaskot	Entergy Corporation	5	Disapprove	

Voter	Entity	Segment	P 1249	Comments
				Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models.R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Timothy VanBlaricom	California ISO	2	Disapprove	Requirement is vague. For entities with large geographic footprints, more specificity in the temperature/humidity requiements is necessary.
Louise McCarren	Western Electricity Coordinating Council	10	Disapprove	Requirement to submit coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 because it is redundant. We recommend an alternative to actually submitting the coincident hourly temperature and humidity data that requires the applicable entity to be able to demonstrate that they record and consider coincident hourly temperature and humidity data when developing forecasts.
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Disapprove	see BPA comments

Voter	Entity	Segment	P 1249	Comments
Jason L. Murray	AESO	2	Disapprove	Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 because it is redundant. We recommend an alternative to actually submitting the coincident hourly temperature and humidity data that requires the applicable entity to be able to demonstrate that they record and consider coincident hourly temperature and humidity data when developing forecasts.
Eric Egge	Black Hills Corp	1	Disapprove	
John Yale	Chelan County Public Utility District #1	5	Disapprove	
Jerome Murray	Oregon Public Utility Commission	9	Disapprove	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Disapprove	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Disapprove	
John Tolo	Tucson Electric Power Co.	1	Disapprove	Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint.
Brandy A Dunn	Western Area Power Administration	1	Disapprove	Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be reported is required.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	Temperature and humidity readings are not well defined over a large BA. EachBA would likely use a slightly different methodology to capture this data,resulting in a non-homogenous dataset. These values are available fromcommercial services and FERC/NERC/Regional entities could specify the datathey needed from the commercial services for their models.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	

Voter	Entity	Segment	P 1249	Comments
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models.
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models. R2, as written, cwould decrease reliability by allowing a wider bandwidth before action is necessarycurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
Larry Akens	Tennessee Valley	1	Disapprove	The additon of Transmission Planner does not improve or enhance reliability. Facility owners

Voter	Entity	Segment	P 1249	Comments
	Authority			(Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are better able to determine which loads "vary based on temperature and/or humidity" and so should be listed in secton 4, Applicability. Temperature and humidity readings are not well defined, especially over a BA of large geographical area. Requirement 2 as written decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Requirement 1.5 is not clear and needs to be reviewed by a SDT.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	The humidity requirement seem unreasonable
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Gregory Campoli	New York Independent System Operator	2	Disapprove	The proposed change to add the clarification “for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year” does not support reliability for the following reasons: 1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to collect the information at that time 2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA’s varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the individual LSE loads has no meaning for Interconnection reliability. If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence. 3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities. 4. FERC’s claim that such weather information analysis can be useful does not

Voter	Entity	Segment	P 1249	Comments
				recognize that there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research but not a good reason to mandate data. 5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	The proposed change to add the clarification “for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year” does not support reliability for the following reasons: 1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to collect the information at that time 2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA’s varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the individual LSE loads has no meaning for Interconnection reliability. If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence. 3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities. 4. FERC’s claim that such weather information analysis can be useful does not recognize that there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research but not a good reason to mandate data. 5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.
Charles H Yeung	Southwest Power Pool	2	Disapprove	The proposed change to add the clarification “for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year” does not support reliability for the following reasons:1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to

Voter	Entity	Segment	P 1249	Comments
				collect the information at that time2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA's varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the individual LSE loads has no meaning for Interconnection reliability.If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence.3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities.4. FERC's claim that such weather information analysis can be useful does not recognize that such there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research but not a good reason to mandate data.5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	The proposed changes to MOD-017 to meet FERC directives in paragraphs 1249 - 1255 are complex and do not represent simple changes The existing modifications while attempting to meet the letter of the FERC Orders, is unable to clearly identify all data to meet a specified reliability goal improvement. Neither FERC nor NERC has shown how weather normalizing or reporting biasing will improve reliability. Biasing is vague and undefined. Therefore NERC considered this FERC directive and met its obligation to address a FERC Order. Nothing states that NERC or the industry must accept a vague or undefined FERC directive.
Nickesha P Carrol	ConEd of NY	6	Disapprove	The proposed wording is impractical. Suggest requirement specify Daily day-ahead peak hour data.
Christopher L de Graffenried	ConEd of NY	1	Disapprove	
Wilket (Jack)	ConEd of NY	5	Disapprove	

Voter	Entity	Segment	P 1249	Comments
Ng				
Laurie Williams	Public Service Co. of New Mexico	1	Disapprove	The requirement to submit hourly temperature and humidity data is not well defined and should be omitted as a requirement. Instead to address the question of whether or not forecasts are weather normalized, consider a method by which the reporting entities could certify that their data is WN or some alternative that does not require submission of this data.
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Disapprove	There is too much diversity within our area as well as within the WECC region.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	Throughout this entire standard it seems as though the terms "demand" and "load" are used interchangeably and terms are capitalized radomly, which appears to be messy. More importantly, regarding the FERC directive, it's seems difficult to report temperature and humidity data across a large entity like an RTO Planning Authority; the humidity/temps vary from one end to the other.
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	Various weather stations can be in a service area, which ones are to be provided? Not all stations may be used in forecasts and different stations may be used in summer versus winter, given variations in load response (more heating load in winter in one area compared to air conditioning load in summer).
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	Various weather stations can be in a service area, which ones are to be provided? Not all stationsmay be used in forecasts and different stations may be used in summer versus winter, givenvariations in load rcsponse (more hearing jad in winter in one area compared ro air conditioningload in summer).
Terry L. Blackwell	Santee Cooper	1	Disapprove	We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Disapprove	We disapprove with the directives in Paragraphs 1249 and 1250. How we'd submit coincident hourly temperatures and humidity data is not defined well enough. For large footprints weather stations, temperatures, and humidity vary across that footprint. Are we to use average data? Do we need to add / invest in new weather stations? Also, making us report coincident hourly temp/humidity for Net Energy For Load is confusing. We think a better avenue would be for the entity to demonstrate they record and consider coincident hourly temperature when we/they develop forecasts. We should not be penalized for not being able to provide data from a weather station tha tis near the load if it is not available. We feel requirement R1.1 should read "Integrated hourly demands in megawatts for the prior year along with the coincident hourly temperature from weather station(s) in proximity to the load center(s) and if available hourly humidity from those same weather stations."Using monthly

Voter	Entity	Segment	P 1249	Comments
				temp can yield poor results, especially in shoulder months where you see both heating and cooling impacts in that same month (ie, April, October). And given that we've already provided data in Requirement 1.1 makes this request redundant and of no value. Analysts will be able to calculate the necessary HDD and or CDD using the hourly data provided in R1.1 for their analysis. We'd like R 1.2 to read " Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. If hourly temperatures were not provided in Requirement 1.1 provide Heating and Cooling degree days base 65, and humidity data for the prior year from weather station(s) in proximity to the load center(s)."
Kim Warren	IESO	2	Disapprove	We do not agree with the changes to R1.2, in particular the second sentence which asks for weather data which is redundant with that already provided in R1.1.
Bob C. Thomas	Illinois Municipal Electric Agency	4	Disapprove	What will this additional data reporting accomplish? Has a problem been identified with the current MOD-017 reporting that needs to be resolved? If so, it hasn't been communicated. These proposed revisions need further vetting to adequately assess the need and the impact on entity resources, particularly small entity resources.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	While the proposed changes may meet directives in paragraph 1249 and 1250, we do not believe this represents the solution that is needed. For one, there is no clear or apparent use of the data being supplied. If the data is to gauge the accuracy of load forecast, FERC already directed the ERO to write other requirements to assess accuracy. Secondly, the requirement does not indicate what data is to be supplied. Is it the data that the entity uses for input into their load forecast model? Is it the data for every major city? Thirdly, each load forecast is highly dependent on the model being used. While some entities may use dozens of locations for weather input others may not. Thus, any effort to normalize load to weather will be dependent on the process/model that the ERO or the Region Entity is using. The data supplied may not match the needs of the ERO or Regional Entity. Because this information is so readily available, it only makes sense for the ERO and Regional Entities to gather the information from an appropriate commercial service to ensure the data meets their needs. Modifying sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.

Voter	Entity	Segment	P 1249	Comments
Jeffrey Mueller	PSE&G	3	Approve	While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	While the PSEG Companies are voting to approve, PSEG Companies believe that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.

Voter	Entity	Segment	P 1249 VSL changes	Comments
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Donald S. Watkins	Bonneville Power Administration	1	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Gregg R Griffin	City of Green Cove Springs	3	In Favor	
Alan Gale	City of Tallahassee	5	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
David A. Lapinski	Consumers Energy	3	In Favor	
David Frank Ronk	Consumers Energy	4	In Favor	

Voter	Entity	Segment	P 1249 VSL changes	Comments
James B Lewis	Consumers Energy	5	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Rex A Roehl	Indeck Energy Services, Inc.	5	In Favor	
Donald Gilbert	JEA	5	In Favor	
Charles Locke	Kansas City Power & Light Co.	3	In Favor	
Michael Gammon	Kansas City Power & Light Co.	1	In Favor	

Voter	Entity	Segment	P 1249 VSL changes	Comments
Walt Gill	Lake Worth Utilities	1	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Doug Bantam	LES	1	In Favor	
Dennis Florom	LES	5	In Favor	
Eric Ruskamp	LES	6	In Favor	
Steven Grego	MEAG Power	3	In Favor	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
Chifong L.	Pacific Gas and	1	In Favor	

Voter	Entity	Segment	P 1249 VSL changes	Comments
Thomas	Electric Co.			
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J.	RRI Energy	5	In Favor	

Voter	Entity	Segment	P 1249 VSL changes	Comments
Bradish				
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
Jeff Nelson	Springfield Utility Board	3	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
Jonathan Appelbaum	United Illuminating Co.	1	In Favor	
Brandy A Dunn	Western Area Power Administration	1	In Favor	

Voter	Entity	Segment	P 1249 VSL changes	Comments
Louise McCarren	Western Electricity Coordinating Council	10	In Favor	
Liam Noailles	Xcel Energy, Inc.	5	In Favor	
Raj Rana	AEP	3	Opposed	
Edward P. Cox	AEP Marketing	6	Opposed	
Brock Ondayko	AEP Service Corp.	5	Opposed	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Rodney Phillips	Allegheny Power	1	Opposed	
Bob Reeping	Allegheny Power	3	Opposed	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Opposed	
Francis J. Halpin	Bonneville Power Administration	5	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Daniel Herring	Detroit Edison Co.	4	Opposed	
Robert Smith	Duke Energy	5	Opposed	
Douglas E.	Duke Energy	1	Opposed	

Voter	Entity	Segment	P 1249 VSL changes	Comments
Hils	Carolina			
Walter Yeager	Duke Energy Carolina	6	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
George R. Bartlett	Entergy Corporation	1	Opposed	
Stanley M Jaskot	Entergy Corporation	5	Opposed	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Opposed	
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	

Voter	Entity	Segment	P 1249 VSL changes	Comments
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
John Bos	Muscatine Power & Water	3	Opposed	
Saurabh Saksena	National Grid	1	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Tim Hattaway	PowerSouth Energy Cooperative	5	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	

Voter	Entity	Segment	P 1249 VSL changes	Comments
Mark A. Heimbach	PPL Generation LLC	5	Opposed	
Laurie Williams	Public Service Co. of New Mexico	1	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	
Terry L. Blackwell	Santee Cooper	1	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	
Richard McLeon	South Texas Electric Cooperative	1	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
George T. Ballew	Tennessee Valley Authority	5	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	

Voter	Entity	Segment	P 1249 VSL changes	Comments
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 1249 in their current format, we cannot support the changes to the VSLs.
Brenda S. Anderson	Bonneville Power Administration	6	Opposed	Did not mean to click opposed or in favor - please disregard response.
Steve Alexanderson	Central Lincoln PUD	3	Opposed	Fix requirements before VSLs
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Dennis Sismaet	Seattle City Light	6	Opposed	In the directives in Paragraph 1250 Alcoa's proposal was rejected because it appears to provide a broad exemption to the Reliability Standard due to the subjective nature of determining whether a load varies with temperature and/or humidity. Regardless of the variability of load with these weather elements, providing the weather data with the loads allows all who are trying to assess or validate past events and databases with the data to make sound mathematical or statistical determinations. Not having the data does not ensure this capability which is the purpose of the Standard. Thus the words "that vary" should be removed from Requirement R1.1. Further, entities do not want to be penalized for not being able to provide the data from a weather station that is near the load if it is not available, nor do entities want to establish weather capturing capabilities. Thus, Requirement R1.1. should be changed to read something like "Integrated hourly demands in megawatts(MW) for the prior year along with coincident hourly temperature from weather station(s) in proximity to the load center(s) and if available hourly humidity from the same weather stations." Because monthly loads may experience heating and cooling impacts in the same month, using monthly temperature is not the best method to approach analyzing temperature impacts on monthly date. Further, by having already provided hourly weather data in Requirement 1.1 make the request for the monthly temperature data in Requirement 1.2 redundant and really worthless. Typically, the monthly analysis of energy and temperature is done using Heating and Cooling Degree Days(HDD/CDD). Any analyst should be able to calculate the necessary HDD and or CDD using the hourly data provided in Requirement 1.1 for the analysis. Requirement 1.2 should be changed to read something similar to this "Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. If hourly temperatures were not provided in Requirement 1.1 provide Heating and Cooling degree days base 65, and humidity data for the prior

Voter	Entity	Segment	P 1249 VSL changes	Comments
				year from weather station(s) in proximity to the load center(s)".
Terry L Baker	Platte River Power Authority	3	Opposed	Loads not only vary based upon temperature and/or humidity, but sunshine index as well. The economy has also played a big role in forecast inaccuracies.
John C. Collins	Platte River Power Authority	1	Opposed	Loads not only vary based upon temperature and/or humidity, but sunshine index as well. The economy has also played a big role in forecast inaccuracies.
Brad Jones	Luminant Energy	6	Opposed	No opinion
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.
Kim Warren	IESO	2	Opposed	R1.2 needs to be fixed first.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Opposed	R1.5 is out of place here
Harold Taylor, II	GTC	1	Opposed	Refer to comments above
Guy Andrews	Georgia System Operations Corporation	4	Opposed	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Opposed	See BPA comments
Russell A Noble	Cowlitz County PUD	3	Opposed	See comment above. VSL for not providing weather information should always be a lower level.
Rick Syring	Cowlitz County PUD	4	Opposed	
Donald E. Nelson	Commonwealth of Massachusetts	9	Opposed	The inclusion of VRFs and VSL's to versions of standards that do not have them should be fully vetted by the industry.

Voter	Entity	Segment	P 1249 VSL changes	Comments
	Department of Public Utilities			
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	The proposed change to add the clarification "for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year" does not support reliability for the following reasons: 1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to collect the information at that time 2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA's varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the individual LSE loads has no meaning for Interconnection reliability. If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence. 3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities. 4. FERC's claim that such weather information analysis can be useful does not recognize that there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research but not a good reason to mandate data. 5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.
Bob Essex	Cowlitz County PUD	5	Opposed	VSL for not providing weather information should always be a lower level.
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P1250:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1250	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	American Public Power Association	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Linda R. Jacobson	City of Farmington	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	

Voter	Entity	Segment	P 1250	Comments
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant	5	Abstain	

Voter	Entity	Segment	P 1250	Comments
	Generation Co. LLC			
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Brandy A Dunn	Western Area Power Administration	1	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Rodney	Allegheny Power	1	Approve	

Voter	Entity	Segment	P 1250	Comments
Phillips				
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth	Gainesville	3	Approve	

Voter	Entity	Segment	P 1250	Comments
Simmons	Regional Utilities			
Charles Locke	Kansas City Power & Light Co.	3	Approve	
Michael Gammon	Kansas City Power & Light Co.	1	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Steven Grego	MEAG Power	3	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	

Voter	Entity	Segment	P 1250	Comments
David T. Anderson	Ocala Electric Utility	3	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James	Progress Energy	6	Approve	

Voter	Entity	Segment	P 1250	Comments
Eckelkamp				
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	

Voter	Entity	Segment	P 1250	Comments
Scott M. Helyer	Tenaska, Inc.	5	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Edward P. Cox	AEP Marketing	6	Disapprove	
Bob Reeping	Allegheny Power	3	Disapprove	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Daniel Herring	Detroit Edison Co.	4	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky	3	Disapprove	

Voter	Entity	Segment	P 1250	Comments
	Power Coop.			
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Donald Gilbert	JEA	5	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	
Gregory Campoli	New York Independent System Operator	2	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	

Voter	Entity	Segment	P 1250	Comments
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Laurie Williams	Public Service Co. of New Mexico	1	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
James L.	Southwest Transmission	1	Disapprove	

Voter	Entity	Segment	P 1250	Comments
Jones	Cooperative, Inc.			
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. General comment - Each entity’s expertise should be relied upon to gather the appropriate weather information.4. In Requirement R1.5 - What is meant by “biasing of each load forecast”?5. With respect to Requirement R1.5 - Is this applicable to Demand Response?6. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 7. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 8. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.
Kirit S. Shah	Ameren Services	1	Disapprove	All referenced requirements need to explicitely address DSM, or the effect of DSM, on the forecast. The drafting team should clearly define how DSM should be considered, that is as an interruptible load or as a resource.
Mel Jensen	APS	5	Disapprove	AZPS does not agree with how NERC has revised the standard to comply with Order 693. Our reading is the FERC is requesting temperature and humidity readings for the peak load, interpreted as Peak Day. The Standard as proposed is over-reaching as it requires weather data for each and every hour of every day (8760).
Robert D Smith	Arizona Public Service Co.	1	Disapprove	
Jerome	Oregon Public	9	Disapprove	Comment: Submitting coincident hourly temperature and humidity data is not defined well enough.

Voter	Entity	Segment	P 1250	Comments
Murray	Utility Commission			For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 because it is redundant. We recommend an alternative to actually submitting the coincident hourly temperature and humidity data that requires the applicable entity to be able to demonstrate that they record and consider coincident hourly temperature and humidity data when developing forecasts.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
David Murray	PSEG Power LLC	5	Approve	Comments: While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Bob Essex	Cowlitz County PUD	5	Approve	Cowlitz votes affirmative under protest to preserve the greater good of the ANSI standard development process. The FERC Order does not adequately address true reliability concerns nor give due weight to the technical expertise of the ERO; the FERC unlawfully substitutes its own expertise. Weather data is already available from NOAA and other organizations for thousands of locations throughout the US. Requiring utilities provide this data in addition is duplicative and unnecessary and distracts utility staff from engaging in work that could improve forecasting and reliability.
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Bethany Wright	SMUD	5	Disapprove	Disapprove changes for directives in Paragraphs 1249 and 1250. Comment: Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be
James Leigh-Kendall	SMUD	3	Disapprove	
Mike Ramirez	SMUD	4	Disapprove	
Tim Kelley	SMUD	1	Disapprove	

Voter	Entity	Segment	P 1250	Comments
				reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 because it is redundant. We recommend an alternative to actually submitting the coincident hourly temperature and humidity data that requires the applicable entity to be able to demonstrate that they record and consider coincident hourly temperature and humidity data when developing forecasts.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE defers to and supports its RTO organizations (PJM and MISO) regarding the proposed load forecasting changes.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	For an entity that covers a diverse area, it is unclear where the temperature and humidity readings are to be taken, or if many (how many?) readings are to be averaged. And why does the entity that has a variation on temperature but not humidity, still need to report humidity?
Danny McDaniel	Cleco Power LLC	1	Disapprove	For an entity that covers a diverse area, it is unclear where the temperature and humidity readings are to be taken, or how many readings are required. Also, we provide such data, hourly demands, to SPP per their form. The change would require a change in the submittal form. The rest of the data is submitted in EIA-411. Will EIA-411 form be revised to accommodate this new information?
Bryan Y Harper	Cleco Utility Group	3	Disapprove	For an entity that covers a diverse area, it is unclear where the temperature and humidity readings are to be taken, or how many readings are required. Also, we provide such data, hourly demands, to SPP per their form. The change would require a change in the submittal form. The rest of the data is submitted in EIA-411. Will EIA-411 form be revised to accommodate this new information?
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	In R1.1 and R1.2 the terminology "loads that vary based on temperature and /or humidity" needs further clarification, i.e. specifically define weather sensitive loads. R1.5 is out of place here, this pertains to day ahead forecasting while the rest of MOD 17 addresses the long term forecast.
Saurabh Saksena	National Grid	1	Disapprove	In requirement R1.1, the location of the reading for coincident hourly temperature and humidity is not clear. Also, in National Grid, the record keeping is done on aggregate basis and not on daily basis. The data is taken from weather services and it is not an automatic process of data collection.
Brenda S. Anderson	Bonneville Power Administration	6	Disapprove	In the directives in Paragraph 1250 Alcoa's proposal was rejected because it appears to provide a broad exemption to the Reliability Standard due to the subjective nature of determining whether a load varies with temperature and/or humidity. Regardless of the variability of load with these weather elements, providing the weather data with the loads allows all who are trying to assess or
Donald S. Watkins	Bonneville Power Administration	1	Disapprove	

Voter	Entity	Segment	P 1250	Comments
Francis J. Halpin	Bonneville Power Administration	5	Disapprove	validate past events and databases with the data to make sound mathematical or statistical determinations. Not having the data does not ensure this capability which is the purpose of the Standard. Thus the words “that vary” should be removed from Requirement R1.1. Further, entities do not want to be penalized for not being able to provide the data from a weather station that is near the load if it is not available, nor do entities want to establish weather capturing capabilities. Thus, Requirement R1.1. should be changed to read something like “Integrated hourly demands in megawatts(MW) for the prior year along with coincident hourly temperature from weather station(s) in proximity to the load center(s) and if available hourly humidity from the same weather stations.” Because monthly loads may experience heating and cooling impacts in the same month, using monthly temperature is not the best method to approach analyzing temperature impacts on monthly date. Further, by having already provided hourly weather data in Requirement 1.1 make the request for the monthly temperature data in Requirement 1.2 redundant and really worthless. Typically, the monthly analysis of energy and temperature is done using Heating and Cooling Degree Days(HDD/CDD). Any analyst should be able to calculate the necessary HDD and or CDD using the hourly data provided in Requirement 1.1 for the analysis. Requirement 1.2 should be changed to read something similar to this “Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. If hourly temperatures were not provided in Requirement 1.1 provide Heating and Cooling degree days base 65, and humidity data for the prior year from weather station(s) in proximity to the load center(s)”.
Rebecca Berdahl	Bonneville Power Administration	3	Disapprove	
Dana Wheelock	Seattle City Light	3	Disapprove	
Dennis Sismaet	Seattle City Light	6	Disapprove	
Hao Li	Seattle City Light	4	Disapprove	
Pawel Krupa	Seattle City Light	1	Disapprove	
John Yale	Chelan County Public Utility District #1	5	Disapprove	included in 1249
Terry L Baker	Platte River Power Authority	3	Disapprove	Loads not only vary based upon temperature and/or humidity, but sunshine index as well. The economy has also played a big role in forecast inaccuracies.
John C. Collins	Platte River Power Authority	1	Disapprove	
Greg C Parent	Manitoba Hydro	3	Disapprove	o Paragraph 1250: They are rejecting Alcoa's idea that not all loads depend on temperature and humidity. They need to trust that we will supply the info needed for weather normalization. Maybe it’s wind and cloud cover. Maybe it’s temperatures at 6 different cities.
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraphs 1249 and 1250 - While we could report both hourly temperature and humidity for the prior year, we don't use humidity for either the forecast or weather normalization, so we would like to have language that makes it an option to be used in the forecasting process, particularly if our

Voter	Entity	Segment	P 1250	Comments
				forecast meets the accuracy requirement.
John K Loftis	Dominion Virginia Power	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. Some examples are cited below:1. We do not agree that addition of the Transmission Planner, in and of itself, improves or enhances reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads "vary based on temperature and/or humidity" and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads "vary based on temperature and/or humidity" and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.2. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models.3. R2, as written, could decrease reliability by allowing a wider bandwidth before action iscurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
George R. Bartlett	Entergy Corporation	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads "vary based on temperature and/or humidity" and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and
Stanley M Jaskot	Entergy Corporation	5	Disapprove	

Voter	Entity	Segment	P 1250	Comments
				Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models.R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	Refer to comments in paragraph 1249 above.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	Refer to comments in paragraph 1249 above.
Timothy VanBlaricom	California ISO	2	Disapprove	Requirement is vague. For entities with large geographic footprints, more specificity in the temperature/humidity requiements is necessary.
Louise McCarren	Western Electricity Coordinating Council	10	Disapprove	Requirement to submit coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity data are to be reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 because it is redundant. We recommend an alternative to actually submitting the coincident hourly temperature and humidity data that requires the applicable entity to be able to demonstrate that

Voter	Entity	Segment	P 1250	Comments
				they record and consider coincident hourly temperature and humidity data when developing forecasts.
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Disapprove	same comment as Par. 1249
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Disapprove	see BPA comments
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	See comment above.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Brock Ondayko	AEP Service Corp.	5	Disapprove	See comments for Paragraph 1249
Harold Taylor, II	GTC	1	Disapprove	
Raj Rana	AEP	3	Disapprove	
Michael F Gildea	Dominion Resources Services	3	Disapprove	See comments to question #25.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
Jason L. Murray	AESO	2	Disapprove	Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint. That leads to the questions: 1) Would average data then be required? or 2) Would multiple temperature and humidity values across multiple weather stations of the reporting entity be required?. Requiring coincident hourly temperature and humidity data for the Net Energy for Load in gigawatthours does not make sense. Clarity in how the coincident hourly temperature and humidity
Eric Egge	Black Hills Corp	1	Disapprove	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Disapprove	

Voter	Entity	Segment	P 1250	Comments
				data are to be reported is required. The data provided in response to R1.1, once clarified, should be adequate to address the directive and it does not need to be specified again in R1.2 because it is redundant. We recommend an alternative to actually submitting the coincident hourly temperature and humidity data that requires the applicable entity to be able to demonstrate that they record and consider coincident hourly temperature and humidity data when developing forecasts.
John Tolo	Tucson Electric Power Co.	1	Disapprove	Submitting coincident hourly temperature and humidity data is not defined well enough. For a reporting entity with a sufficiently large footprint, temperature and humidity data could vary across the footprint.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	Temperature and humidity readings are not well defined over a large BA. EachBA would likely use a slightly different methodology to capture this data,resulting in a non-homogenous dataset. These values are available fromcommercial services and FERC/NERC/Regional entities could specify the datathey needed from the commercial services for their models.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
Larry Akens	Tennessee Valley Authority	1	Disapprove	The additon of Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are better able to determine which loads "vary based on temperature and/or humidity" and so should be listed in secton 4, Applicability. Temperature and humidity readings are not well defined, especially over a BA of large geographical area. Requirement 2 as written decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Requirement 1.5 is not clear and needs to be reviewed by a SDT.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	The additon of Transmssion Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possible Load Serving Entity) meter usage and therefore are bet able to determine which loads "vary based on temprature and/or humidity" and so shojld be listed in secton 4, Applicability. Temperature and humidity readings are not well defined, especially over a BA of large geographical area. Requirement 2 as written decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Requirement 1.5 is not

Voter	Entity	Segment	P 1250	Comments
				clear and needs to be reviewed by a SDT.
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models. R2, as written, cwould decrease reliability by allowing a wider bandwidth before action is necessarycurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Tom Bowe	PJM Interconnection,	2	Disapprove	The proposed change to add the clarification “for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year” does not support

Voter	Entity	Segment	P 1250	Comments
	L.L.C.			reliability for the following reasons: 1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to collect the information at that time 2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA's varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the individual LSE loads has no meaning for Interconnection reliability. If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence. 3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities. 4. FERC's claim that such weather information analysis can be useful does not recognize that there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research but not a good reason to mandate data. 5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.
Charles H Yeung	Southwest Power Pool	2	Disapprove	The proposed change to add the clarification "for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year" does not support reliability for the following reasons:1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to collect the information at that time2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA's varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the

Voter	Entity	Segment	P 1250	Comments
				individual LSE loads has no meaning for Interconnection reliability.If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence.3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities.4. FERC's claim that such weather information analysis can be useful does not recognize that such there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research but not a good reason to mandate data.5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	The proposed changes to MOD-017 to meet FERC directives in paragraphs 1249 - 1255 are complex and do not represent simple changes The existing modifications while attempting to meet the letter of the FERC Orders, is unable to clearly identify all data to meet a specified reliability goal improvement. Neither FERC nor NERC has shown how weather normalizing or reporting biasing will improve reliability. Biasing is vague and undefined. Therefore NERC considered this FERC directive and met its obligation to address a FERC Order. Nothing states that NERC or the industry must accept a vague or undefined FERC directive.
Daniel Prowse	Manitoba Hydro	6	Disapprove	They are rejecting Alcoa's idea that not all loads depend on temperature and humidity. They need to trust that we will supply the info needed for weather normalization. Maybe it's wind and cloud cover. Maybe it's temperatures at 6 different cities.
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	Throughout this entire standard it seems as though the terms "demand" and "load" are used interchangeably and terms are capitalized radomly, which appears to be messy. More importantly, regarding the FERC directive, it's seems difficult to report temperature and humidity data across a large entity like an RTO Planning Authority; the humidity/temps vary from one end to the other.
Terry L. Blackwell	Santee Cooper	1	Disapprove	We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Kim Warren	IESO	2	Disapprove	We do not agree with the changes to R1.2, in particular the second sentence which asks for weather

Voter	Entity	Segment	P 1250	Comments
				data which is redundant with that already provided in R1.1.
Bob C. Thomas	Illinois Municipal Electric Agency	4	Disapprove	What will this additional data reporting accomplish? Has a problem been identified with the current MOD-017 reporting that needs to be resolved? If so, it hasn't been communicated. These proposed revisions need further vetting to adequately assess the need and the impact on entity resources, particularly small entity resources.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	While the proposed changes may meet directives in paragraph 1249 and 1250, we do not believe this represents the solution that is needed. For one, there is no clear or apparent use of the data being supplied. If the data is to gauge the accuracy of load forecast, FERC already directed the ERO to write other requirements to assess accuracy. Secondly, the requirement does not indicate what data is to be supplied. Is it the data that the entity uses for input into their load forecast model? Is it the data for every major city? Thirdly, each load forecast is highly dependent on the model being used. While some entities may use dozens of locations for weather input others may not. Thus, any effort to normalize load to weather will be dependent on the process/model that the ERO or the Region Entity is using. The data supplied may not match the needs of the ERO or Regional Entity. Because this information is so readily available, it only makes sense for the ERO and Regional Entities to gather the information from an appropriate commercial service to ensure the data meets their needs. Modifying sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Jeffrey Mueller	PSE&G	3	Approve	While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	While the PSEG Companies are voting to approve, PSEG Companies believe that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.

Voter	Entity	Segment	P 1250 VSL changes	Comments
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Gregg R Griffin	City of Green Cove Springs	3	In Favor	
Alan Gale	City of Tallahassee	5	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
David A. Lapinski	Consumers Energy	3	In Favor	
David Frank Ronk	Consumers Energy	4	In Favor	
James B Lewis	Consumers Energy	5	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	

Voter	Entity	Segment	P 1250 VSL changes	Comments
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Rex A Roehl	Indeck Energy Services, Inc.	5	In Favor	
Donald Gilbert	JEA	5	In Favor	
Charles Locke	Kansas City Power & Light Co.	3	In Favor	
Michael Gammon	Kansas City Power & Light Co.	1	In Favor	
Walt Gill	Lake Worth Utilities	1	In Favor	

Voter	Entity	Segment	P 1250 VSL changes	Comments
Larry E Watt	Lakeland Electric	1	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Doug Bantam	LES	1	In Favor	
Dennis Florom	LES	5	In Favor	
Eric Ruskamp	LES	6	In Favor	
Steven Grego	MEAG Power	3	In Favor	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	In Favor	
John Bos	Muscatine Power & Water	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	

Voter	Entity	Segment	P 1250 VSL changes	Comments
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility	3	In Favor	

Voter	Entity	Segment	P 1250 VSL changes	Comments
	District No. 2 of Grant County			
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
Jeff Nelson	Springfield Utility Board	3	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
Jonathan Appelbaum	United Illuminating Co.	1	In Favor	

Voter	Entity	Segment	P 1250 VSL changes	Comments
Brandy A Dunn	Western Area Power Administration	1	In Favor	
Louise McCarren	Western Electricity Coordinating Council	10	In Favor	
Raj Rana	AEP	3	Opposed	
Edward P. Cox	AEP Marketing	6	Opposed	
Brock Ondayko	AEP Service Corp.	5	Opposed	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Rodney Phillips	Allegheny Power	1	Opposed	
Bob Reeping	Allegheny Power	3	Opposed	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Opposed	
Francis J. Halpin	Bonneville Power Administration	5	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Daniel Herring	Detroit Edison Co.	4	Opposed	

Voter	Entity	Segment	P 1250 VSL changes	Comments
Robert Smith	Duke Energy	5	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	
Walter Yeager	Duke Energy Carolina	6	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
George R. Bartlett	Entergy Corporation	1	Opposed	
Stanley M Jaskot	Entergy Corporation	5	Opposed	
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	

Voter	Entity	Segment	P 1250 VSL changes	Comments
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
Saurabh Saksena	National Grid	1	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Tim Hattaway	PowerSouth Energy Cooperative	5	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A. Heimbach	PPL Generation LLC	5	Opposed	

Voter	Entity	Segment	P 1250 VSL changes	Comments
Laurie Williams	Public Service Co. of New Mexico	1	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	
Terry L. Blackwell	Santee Cooper	1	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
James Leigh-Kendall	SMUD	3	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	
Richard McLeon	South Texas Electric Cooperative	1	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
George T. Ballew	Tennessee Valley Authority	5	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	

Voter	Entity	Segment	P 1250 VSL changes	Comments
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 1250 in their current format, we cannot support the changes to the VSLs.
Steve Alexanderson	Central Lincoln PUD	3	Opposed	Fix requirements before VSLs
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Dennis Sismaet	Seattle City Light	6	Opposed	In the directives in Paragraph 1250 Alcoa's proposal was rejected because it appears to provide a broad exemption to the Reliability Standard due to the subjective nature of determining whether a load varies with temperature and/or humidity. Regardless of the variability of load with these weather elements, providing the weather data with the loads allows all who are trying to assess or validate past events and databases with the data to make sound mathematical or statistical determinations. Not having the data does not ensure this capability which is the purpose of the Standard. Thus the words "that vary" should be removed from Requirement R1.1. Further, entities do not want to be penalized for not being able to provide the data from a weather station that is near the load if it is not available, nor do entities want to establish weather capturing capabilities. Thus, Requirement R1.1. should be changed to read something like "Integrated hourly demands in megawatts(MW) for the prior year along with coincident hourly temperature from weather station(s) in proximity to the load center(s) and if available hourly humidity from the same weather stations." Because monthly loads may experience heating and cooling impacts in the same month, using monthly temperature is not the best method to approach analyzing temperature impacts on monthly date. Further, by having already provided hourly weather data in Requirement 1.1 make the request for the monthly temperature data in Requirement 1.2 redundant and really worthless. Typically, the monthly analysis of energy and temperature is done using Heating and Cooling Degree Days(HDD/CDD). Any analyst should be able to calculate the necessary HDD and or CDD using the hourly data provided in Requirement 1.1 for the analysis. Requirement 1.2 should be changed to read something similar to this "Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. If hourly temperatures were not provided in Requirement 1.1 provide Heating and Cooling degree days base 65, and humidity data

Voter	Entity	Segment	P 1250 VSL changes	Comments
				for the prior year from weather station(s) in proximity to the load center(s)".
Terry L Baker	Platte River Power Authority	3	Opposed	Loads not only vary based upon temperature and/or humidity, but sunshine index as well. The economy has also played a big role in forecast inaccuracies.
John C. Collins	Platte River Power Authority	1	Opposed	
Brad Jones	Luminant Energy	6	Opposed	No opinion
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.
Kim Warren	IESO	2	Opposed	R1.2 need to be changed first.
Guy Andrews	Georgia System Operations Corporation	4	Opposed	Refer to comments in paragraph 1249 above.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Opposed	See above
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Opposed	See BPA comments
Harold Taylor, II	GTC	1	Opposed	See comments for Paragraph 1249 above.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Opposed	The inclusion of VRFs and VSL's to versions of standards that do not have them should be fully vetted by the industry.
Tom Bowe	PJM Interconnection,	2	Opposed	The proposed change to add the clarification "for loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year" does not support

Voter	Entity	Segment	P 1250 VSL changes	Comments
	L.L.C.			reliability for the following reasons: 1. There is no current or proposed NERC initiative that will use the weather information. Why mandate under federal law requirements to send information that will not be used. If and when there is a question about weather data, NERC can use its Rules of Procedure to collect the information at that time 2. There is no clarity what reliability purpose is to be served. If this data is for NERC to analyze and verify peak load data used by PA for operations, then the requirement makes no sense because the weather across PA's varies too greatly to provide one set of coincident numbers. If the data is for NERC to analyze and verify LSE loads, then the requirement makes no sense because NERC does not have a reliability concern about local load estimates, i.e. the granularity of the data is too fine for NERC purposes (i.e. hourly local load/weather data). Indeed the sum of the individual LSE loads has no meaning for Interconnection reliability. If the data is for NERC to analyze and verify loads used for Planning, then the requirement makes no sense because the forecast load data is not based on weather as much as it is based on probability of occurrence. 3. Whether or not the load data is sensitive to weather is a matter for local planners not planners that report wide-area assessments to NERC. Some regions of NERC are now coming to grips with the reasonableness of doing local area analyses for wide area operations. It is one thing to do a local analysis; it is another thing to use that analysis in a meaningful way for NERC BES analysis and assessments. A 100% forecasting error by all LSEs would not necessarily impact any NERC reliability standard as long as the wide area diversified peak load was correctly forecasted and used by the reliability entities. 4. FERC's claim that such weather information analysis can be useful does not recognize that there is no current or planned project to do such analysis. There is no identified need to do such an analysis. The FERC proposal is a good basis for research but not a good reason to mandate data. 5. Committing staff to provide data for the sake of providing data will take staff away from actual useful work.
Bob Essex	Cowlitz County PUD	5	Opposed	VSL for not providing weather information should always be a lower level.
Rick Syring	Cowlitz County PUD	4	Opposed	
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P1251:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1251	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	American Public Power Association	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	

Voter	Entity	Segment	P 1251	Comments
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant	5	Abstain	

Voter	Entity	Segment	P 1251	Comments
	Generation Co. LLC			
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Jason L. Murray	AESO	2	Approve	
Kevin Koloini	American Municipal Power -	4	Approve	

Voter	Entity	Segment	P 1251	Comments
	Ohio			
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Lee Schuster	Florida Power	3	Approve	

Voter	Entity	Segment	P 1251	Comments
	Corporation			
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Steven Grego	MEAG Power	3	Approve	
Dan R. Schoenecker	MRO	10	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R.	Otter Tail Power	1	Approve	

Voter	Entity	Segment	P 1251	Comments
Larson	Co.			
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of	3	Approve	

Voter	Entity	Segment	P 1251	Comments
	Chelan County			
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Jeff Nelson	Springfield Utility	3	Approve	

Voter	Entity	Segment	P 1251	Comments
	Board			
Scott M. Helyer	Tenaska, Inc.	5	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
Rodney Phillips	Allegheny Power	1	Disapprove	
Bob Reeping	Allegheny Power	3	Disapprove	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Danny McDaniel	Cleco Power LLC	1	Disapprove	
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Daniel	Detroit Edison Co.	4	Disapprove	

Voter	Entity	Segment	P 1251	Comments
Herring				
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	

Voter	Entity	Segment	P 1251	Comments
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	
Randi Woodward	Minnesota Power, Inc.	1	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Laurie Williams	Public Service Co. of New Mexico	1	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	

Voter	Entity	Segment	P 1251	Comments
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. General comment - Each entity’s expertise should be relied upon to gather the appropriate weather information.4. In Requirement R1.5 - What is meant by “biasing of each load forecast”?5. With respect to Requirement R1.5 - Is this applicable to Demand Response?6. With respect to Requirement R2.0 - Remove the

Voter	Entity	Segment	P 1251	Comments
				wording in the parentheses. Each entity has to look at its forecast error. 7. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 8. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.
Kirit S. Shah	Ameren Services	1	Disapprove	All referenced requirements need to explicitely address DSM, or the effect of DSM, on the forecast. The drafting team should clearly define how DSM should be considered, that is as an interruptible load or as a resource.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
David Murray	PSEG Power LLC	5	Approve	Comments: While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	day ahead hourly forecasts should not be included in mod-17 and R1.5 should be modified to remove day ahead hourly for each hour since only montly and annual peak loads are being forecast in R1.3 as part of planning horizons.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	Day-ahead hourly forcasting should not be included in MOD-017 R1.5. R1.3 refers to monthly and annual peak load forecasts as part of planning horizon efforts. Load forecasting in the planning horizon is different than load forecasting in the operating horizon.
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted hourly loads and actual hourly loads as indicated by proposed additions of requirements R1.5 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading. In addition, techniques

Voter	Entity	Segment	P 1251	Comments
				developed by load forecasting groups to “compare” actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted hourly loads and actual hourly loads as indicated by proposed additions of requirements R1.5 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading.In addition, techniques developed by load forecasting groups to “compare” actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE defers to and supports its RTO organizations (PJM and MISO) regarding the proposed load forecasting changes.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	Forecasted hourly data for what period of time? What is the value of this 10yrs out?
Saurabh Saksena	National Grid	1	Disapprove	In Requirement 1.5, is the load on a system basis or on a substation/bus basis? What is meant by “biasing of each load forecast”? Is this applicable to Demand Response? Also, “day-ahead hourly” does not add any value from a Planning perspective since it is a market/operations issue.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	In Requirement R1.5 - What is meant by “biasing of each load forecast”?With respect to Requirement R1.5 - Is this applicable to Demand Response?
Randall McCamish	City of Vero Beach	1	Disapprove	Load forecasting in the planning horizon is performed using a different method and a different purpose than load forecasting in the operating horizon. The MOD standards to not require a Day-ahead hourly forecast, the operating horizon standards do. Hence, Day-ahead hourly load forecasts should not be included in MOD-017 and R1.5 should be modified to remove Day-ahead Hourly for
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	

Voter	Entity	Segment	P 1251	Comments
Walt Gill	Lake Worth Utilities	1	Disapprove	each hour since only monthly and annual peak loads are being forecasted in R1.3 as part of the planning horizon efforts.
Larry E Watt	Lakeland Electric	1	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	MOD-017 R1.5. It is not clear as written. At a minimum, we recommend removing the daily granularity for reporting of hourly load forecast error.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	No explanation on the meaning of "biasing load forecast."
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Greg C Parent	Manitoba Hydro	3	Disapprove	o Paragraph 1251: The intent of Requirement R1.5 is not clear. Is the Monthly peak hour load forecast accuracy referring to a "Month-ahead" peak forecast or is it related to the monthly peak forecast referred to as a requirement in R1.3? Please clarify the lead time surrounding the month-ahead load forecast.
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 1251 - Requirement R1.5 must limit the load forecast accuracy determination to the summer and/or winter peak conditions. Paragraph 1251 does NOT direct hourly assessment of load forecast accuracy. The forecast data provided under R1 is that data needed to perform future system assessment to identify the need for future system reinforcement for continued reliability. The only two hours of the year that we weather normalize are the MW demand at the hour of summer peak and the MW demand at the hour of winter peak. We then compare past forecasts for these two hours to the weather normalized loads to see the level of accuracy for these two hours. We don't look at the other 8760 hours of the year with regard to forecast accuracy and it would be an almost impossible task to do so.
John K Loftis	Dominion Virginia Power	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder

Voter	Entity	Segment	P 1251	Comments
				vetting. Some examples are cited below:1. We do not agree that addition of the Transmission Planner, in and of itself, improves or enhances reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.2. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models.3. R2, as written, could decrease reliability by allowing a wider bandwidth before action iscurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
George R. Bartlett	Entergy Corporation	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify
Stanley M Jaskot	Entergy Corporation	5	Disapprove	

Voter	Entity	Segment	P 1251	Comments
				which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models.R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Donald Gilbert	JEA	5	Disapprove	Planners do not forecst hourly or day ahead demand levels. Planners primarily focus on annual and seasonal peak data and a typical load shape that may not correlate well to weather variables.
David A. Lapinski	Consumers Energy	3	Disapprove	R1.5 includes a requirement for "Day-ahead Hourly . . . load Forecast accuracy . . .". This seems to exceed the focus of the Order, which is oriented toward planning. Additionally, the standard is not clear what is intended by "day-ahead" forecast. There often are multiple "day-ahead" forecasts, as weather forecasts change and current day load patterns emerge. Finally, the text appears to capitalize terms that are not defined in the Glossary.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Kim Warren	IESO	2	Disapprove	R1.5 is confusing. It asks for “day-ahead”, monthly peak and annual peak demands which implies forecast data, yet the wording in parenthesis implies after the fact error assessment. Further, it is unclear what “biasing of each load forecast” means. Is it operator adjustments? If so, isn’t forecaster/operator expertise part of the forecasting process? Forecasting (especially long term) is not just a mechanical exercise but requires “value-added” actions by the forecaster. Biasing is not a defined term. In fact, the entire MOD-017 is confusing as it mixes forecast data with actual data without a clear delineation between the two sets. The standard itself needs reworking to add clarity. The addition of R1.5 makes the standard even more confusing. We suggest this change be pulled off from this round of revision. Further, day-ahead hourly for each hour is not clear. This could represent a large number of forecasts (if multiple day ahead forecasts are made).
Richard J.	Alabama Power Co.	3	Disapprove	R1.5 is not clear, as written, and we suggest that it should be given to astandards drafting team to

Voter	Entity	Segment	P 1251	Comments
Mandes				develop appropriately.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
Dana Wheelock	Seattle City Light	3	Disapprove	SCL respectfully votes negative on the proposed requirement #R1.5 and R2 as it relates to the requirement of providing the day-ahead hourly load forecast for each hour and if necessary, modify load forecast assumptions to improve accuracy to within 10%. The standard needs to be clear whether the intent is to create day-ahead hourly load forecasts where every hour has an accuracy of 10% or less, or if it is sufficient, and more realistic, that a percentage of the hourly forecasts for the year be within a certain % of accuracy. Otherwise, the amount of labor and resources to try to improve the accuracy of making sure every hourly load forecast is accurate to within a certain percentage doesn't take into account that it is a forecast, and hourly forecasts sometimes miss their mark, due to changing weather conditions.
Dennis Sismaet	Seattle City Light	6	Disapprove	SCL respectfully votes negative on the proposed requirement #R1.5 and R2 as it relates to the requirement of providing the day-ahead hourly load forecast for each hour and if necessary, modify load forecast assumptions to improve accuracy to within 10%. The standard needs to be clear whether the intent is to create day-ahead hourly load forecasts where every hour has an accuracy of 10% or less, or if it is sufficient, and more realistic, that a percentage of the hourly forecasts for the year be within a certain % of accuracy. Otherwise, the amount of labor and resources to try to improve the accuracy of making sure every hourly load forecast is accurate to within a certain percentage doesn't take into account that it is a forecast, and hourly forecasts sometimes miss their mark, due to changing weather conditions.Also, the phrase: "as well as any biasing of each load forecast" should be clarified.
Hao Li	Seattle City Light	4	Disapprove	SCL respectfully votes negative on the proposed requirement #R1.5 and R2 as it relates to the requirement of providing the day-ahead hourly load forecast for each hour and if necessary, modify load forecast assumptions to improve accuracy to within 10%. The standard needs to be clear
Pawel Krupa	Seattle City Light	1	Disapprove	

Voter	Entity	Segment	P 1251	Comments
				whether the intent is to create day-ahead hourly load forecasts where every hour has an accuracy of 10% or less, or if it is sufficient, and more realistic, that a percentage of the hourly forecasts for the year be within a certain % of accuracy. Otherwise, the amount of labor and resources to try to improve the accuracy of making sure every hourly load forecast is accurate to within a certain percentage doesn't take into account that it is a forecast, and hourly forecasts sometimes miss their mark, due to changing weather conditions.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	See above
Michael F Gildea	Dominion Resources Services	3	Disapprove	See comments to question #25.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
Doug Bantam	LES	1	Disapprove	The addition of Requirement 1.5 is not clearly stated in terms of what "Day-Ahead Hourly" forecast value should be used for the proposed calculation. Day-Ahead Hourly forecasts can, and often are, revised repeatedly as the target hour is approached. Without explicitly stating the time from during which the day-ahead hourly value should be derived, the calculation could be manipulated to prove nothing.
Dennis Florom	LES	5	Disapprove	
Eric Ruskamp	LES	6	Disapprove	
Larry Akens	Tennessee Valley Authority	1	Disapprove	The additon of Transmssion Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possible Load Serving Entity) meter usage and therefore are bet able to determine which loads "vary based on temprature and/or humidity" and so shojld be listed in secton 4, Applicability. Temperature and humidity readings are not well defined, especially over a BA of large geographical area. Requirement 2 as written decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Requirement 1.5 is not clear and needs to be reviewed by a SDT.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability.

Voter	Entity	Segment	P 1251	Comments
				Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads "vary based on temperature and/or humidity" and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models. R2, as written, cwould decrease reliability by allowing a wider bandwidth before action is necessarycurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
Bob Essex	Cowlitz County PUD	5	Disapprove	The FERC Order does not specifically require a report on the hourly forecast accuracy on the day-ahead scheduling of energy. Requiring entities to provide this data in addition to analysis of the accuracy of long range forecasts is unnecessary. More importantly, we believe there is already sufficient incentive for utilities to review the accuracy of their own day-ahead load forecasts and implement improvement procedures as necessary to minimize errors to the extent possible. Inaccurate forecasts result in sub-optimum planning and as a result, sub-optimum marketing activities and additional power cost for the utility. The added cost incurred as a result of inaccurate forecasts in power scheduling is already incentive enough. Adding reporting requirements to the already existing financial costs is unnecessary and distracts staff from the work of actually improving forecasts and as a result, improving reliability. However, looking at the accuracy of previous submitted data for requirements R1.3 and R1.4 has merit and would help support requirement R2.
Russell A Noble	Cowlitz County PUD	3	Disapprove	
Rick Syring	Cowlitz County PUD	4	Disapprove	
Kathleen	ISO New England,	2	Disapprove	The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be

Voter	Entity	Segment	P 1251	Comments
Goodman	Inc.			fully vetted by the industry. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Daniel Prowse	Manitoba Hydro	6	Disapprove	The intent of Requirement R1.5 is not clear. Is the Monthly peak hour load forecast accuracy referring to a “Month-ahead” peak forecast or is it related to the monthly peak forecast referred to as a requirement in R1.3? Please clarify the lead time surrounding the month-ahead load forecast.
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	The proposed changes to MOD-017 to meet FERC directives in paragraphs 1249 - 1255 are complex and do not represent simple changes The existing modifications while attempting to meet the letter of the FERC Orders, is unable to clearly identify all data to meet a specified reliability goal improvement. Neither FERC nor NERC has shown how weather normalizing or reporting biasing will improve reliability. Biasing is vague and undefined. Therefore NERC considered this FERC directive and met its obligation to address a FERC Order. Nothing states that NERC or the industry must accept a vague or undefined FERC directive.
Gregory Campoli	New York Independent System Operator	2	Disapprove	The proposed changes to R1.5 are confusing. It asks for “day-ahead”, monthly peak and annual peak demands which implies forecast data, yet the wording in parenthesis implies after the fact error assessment. Further, it is unclear what “biasing of each load forecast” means. In fact, the entire MOD-017 is confusing as it mixes forecast data with actual data without a clear delineation between the two sets. The standard itself needs reworking to add clarity. The addition of R1.5 makes the standard even more confusing. We suggest this change be pulled off from this round of revision.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	
Charles H Yeung	Southwest Power Pool	2	Disapprove	
Peter T Yost	ConEd of NY	3	Disapprove	The proposed wording in R1.5 is impractical. Suggest requirement specify Daily day-ahead peak hour data, not Hourly.
Timothy VanBlaricom	California ISO	2	Disapprove	There are 8760 hours per year in a day ahead hourly forecast, and requiring 8760 error analyses is not practical. Monthly error analyses would look at many months that don’t have significance on reliability issues. For R2, weather normalization needs to be addressed. With regard to error divided by actual demand, it is suggested that the error be defined as the absolute value between actual and forecast demand divided by actual demand.
Alan Gale	City of Tallahassee	5	Disapprove	This is mixing planning and operations horizons. It seems like comparing apples to oranges. Planning

Voter	Entity	Segment	P 1251	Comments
				should be considering worst case. Operations should be gettting more realistic and looking at expected conditions.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	Throughout this entire standard it seems as though the terms "demand" and "load" are used interchangeably and terms are capitalized radomly, which appears to be messy. More importantly, regarding the FERC directive, it's seems difficult to report temperature and humidity data across a large entity like an RTO Planning Authority; the humidity/temps vary from one end to the other.
Terry L. Blackwell	Santee Cooper	1	Disapprove	We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We disagree with the proposed changes to address directives in paragraph 1251. While they may technically meet the directive because the wording from the directive was essentially inserted as a sub-requirement, we do not believe that the requirement is clear or represents the best solution. For instance, what is biasing in a load forecast? Additionally, the Commission did not state what load forecast error should be compared. For example, LSEs will have dozens of load forecasts for the same time period that are updated with newer weather information as the operating hour approaches. Why was Day-Ahead selected? Why not seven days ahead? 12 hours ahead, etc.? We believe this directive does not represent low-hanging fruit that can be addressed in an ad hoc manner such as this SAR. Further, because load forecasting is complicated process, we believe it is necessary to retain a group of load forecasting experts in a drafting team to address these directives appropriately so that meaningful requirements can be written.Adding sub-requirement R1.5 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Bob C. Thomas	Illinois Municipal Electric Agency	4	Disapprove	What will this additional data reporting accomplish? Has a problem been identified with the current MOD-017 reporting that needs to be resolved? If so, it hasn't been communicated. These proposed revisions need further vetting to adequately assess the need and the impact on entity resources, particularly small entity resources.
Jeffrey Mueller	PSE&G	3	Approve	While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes

Voter	Entity	Segment	P 1251	Comments
Kenneth D. Brown	PSE&G	1	Approve	proposed as appropriate.
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
Raj Rana	AEP	3	Disapprove	With respect to MOD-017 R1.5, we do not see the benefit to include the day-ahead forecast accuracy to NERC and the Regional Entities.
Edward P. Cox	AEP Marketing	6	Disapprove	
Brock Ondayko	AEP Service Corp.	5	Disapprove	

Voter	Entity	Segment	P 1251 VSL changes	Comments
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Francis J. Halpin	Bonneville Power Administration	5	In Favor	
Rebecca Berdahl	Bonneville Power Administration	3	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Alan Gale	City of Tallahassee	5	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
David A. Lapinski	Consumers Energy	3	In Favor	
David Frank Ronk	Consumers Energy	4	In Favor	
James B Lewis	Consumers Energy	5	In Favor	

Voter	Entity	Segment	P 1251 VSL changes	Comments
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Rex A Roehl	Indeck Energy Services, Inc.	5	In Favor	
Donald Gilbert	JEA	5	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	

Voter	Entity	Segment	P 1251 VSL changes	Comments
Steven M. Jackson	Municipal Electric Authority of Georgia	3	In Favor	
John Bos	Muscatine Power & Water	3	In Favor	
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	

Voter	Entity	Segment	P 1251 VSL changes	Comments
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Terry L Baker	Platte River Power Authority	3	In Favor	
John C. Collins	Platte River Power Authority	1	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	

Voter	Entity	Segment	P 1251 VSL changes	Comments
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Bethany Wright	SMUD	5	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Mike Ramirez	SMUD	4	In Favor	
Tim Kelley	SMUD	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
Jeff Nelson	Springfield Utility Board	3	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
Jonathan Appelbaum	United Illuminating Co.	1	In Favor	
Brandy A Dunn	Western Area Power Administration	1	In Favor	
Louise	Western Electricity	10	In Favor	

Voter	Entity	Segment	P 1251 VSL changes	Comments
McCarren	Coordinating Council			
Raj Rana	AEP	3	Opposed	
Edward P. Cox	AEP Marketing	6	Opposed	
Brock Ondayko	AEP Service Corp.	5	Opposed	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Rodney Phillips	Allegheny Power	1	Opposed	
Bob Reeping	Allegheny Power	3	Opposed	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Bob Essex	Cowlitz County PUD	5	Opposed	
Rick Syring	Cowlitz County PUD	4	Opposed	
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Daniel Herring	Detroit Edison Co.	4	Opposed	
Robert Smith	Duke Energy	5	Opposed	
Douglas E.	Duke Energy	1	Opposed	

Voter	Entity	Segment	P 1251 VSL changes	Comments
Hils	Carolina			
Walter Yeager	Duke Energy Carolina	6	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
George R. Bartlett	Entergy Corporation	1	Opposed	
Stanley M Jaskot	Entergy Corporation	5	Opposed	
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	
Gwen S Frazier	Gulf Power Co.	3	Opposed	

Voter	Entity	Segment	P 1251 VSL changes	Comments
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
John W Delucca	Lee County Electric Cooperative	1	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Tim Hattaway	PowerSouth Energy Cooperative	5	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A. Heimbach	PPL Generation LLC	5	Opposed	
Laurie Williams	Public Service Co. of New Mexico	1	Opposed	

Voter	Entity	Segment	P 1251 VSL changes	Comments
Daniel Baerman	San Diego G&E	5	Opposed	
Terry L. Blackwell	Santee Cooper	1	Opposed	
Dana Wheelock	Seattle City Light	3	Opposed	
Hao Li	Seattle City Light	4	Opposed	
Pawel Krupa	Seattle City Light	1	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	
Richard McLeon	South Texas Electric Cooperative	1	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
RJames Rocha	Tampa Electric Co.	5	Opposed	
Ronald L Donahey	Tampa Electric Co.	3	Opposed	

Voter	Entity	Segment	P 1251 VSL changes	Comments
George T. Ballew	Tennessee Valley Authority	5	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 1251 in their current format, we cannot support the changes to the VSLs.
Brenda S. Anderson	Bonneville Power Administration	6	In Favor	Did not mean to click opposed or in favor - please disregard response.
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Brad Jones	Luminant Energy	6	Opposed	No opinion
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.
Kim Warren	IESO	2	Opposed	R1.5 needs to be changed first.
Charles Locke	Kansas City Power & Light Co.	3	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
Michael Gammon	Kansas City Power & Light Co.	1	Opposed	
Guy Andrews	Georgia System Operations Corporation	4	Opposed	Refer to comments above.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	Refer to comments above.

Voter	Entity	Segment	P 1251 VSL changes	Comments
Harold Taylor, II	GTC	1	Opposed	
Gregg R Griffin	City of Green Cove Springs	3	In Favor	replace "improvements" with "adjustments"
Dennis Sismaet	Seattle City Light	6	Opposed	SCL respectfully votes negative on the proposed requirement #R1.5 and R2 as it relates to the requirement of providing the day-ahead hourly load forecast for each hour and if necessary, modify load forecast assumptions to improve accuracy to within 10%. The standard needs to be clear whether the intent is to create day-ahead hourly load forecasts where every hour has an accuracy of 10% or less, or if it is sufficient, and more realistic, that a percentage of the hourly forecasts for the year be within a certain % of accuracy. Otherwise, the amount of labor and resources to try to improve the accuracy of making sure every hourly load forecast is accurate to within a certain percentage doesn't take into account that it is a forecast, and hourly forecasts sometimes miss their mark, due to changing weather conditions.Also, the phrase: "as well as any biasing of each load forecast" should be clarified.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Opposed	See above
Saurabh Saksena	National Grid	1	Opposed	See comments above.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Opposed	The inclusion of VRFs and VSL's to versions of standards that do not have them should be fully vetted by the industry.
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	The proposed changes to R1.5 are confusing. It asks for “day-ahead”, monthly peak and annual peak demands which implies forecast data, yet the wording in parenthesis implies after the fact error assessment. Further, it is unclear what “biasing of each load forecast” means. In fact, the entire MOD-017 is confusing as it mixes forecast data with actual data without a clear delineation between the two sets. The standard itself needs reworking to add clarity. The addition of R1.5 makes the standard even more confusing. We suggest this change be pulled off from this round of revision.
Walt Gill	Lake Worth Utilities	1	In Favor	Wording is awkward on "High" VSL, consider replacing "improvements" with "adjustments"

Voter	Entity	Segment	P 1251 VSL changes	Comments
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P1252:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1252	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Robert Smith	Duke Energy	5	Abstain	

Voter	Entity	Segment	P 1252	Comments
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating	8	Abstain	

Voter	Entity	Segment	P 1252	Comments
	Cooperative			
Ronald Schloendorn	PECO Energy	1	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Kevin Koloini	American	4	Approve	

Voter	Entity	Segment	P 1252	Comments
	Municipal Power - Ohio			
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn	Constellation	3	Approve	

Voter	Entity	Segment	P 1252	Comments
Ingersoll	Energy			
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	

Voter	Entity	Segment	P 1252	Comments
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	

Voter	Entity	Segment	P 1252	Comments
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	

Voter	Entity	Segment	P 1252	Comments
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
Rodney Phillips	Allegheny Power	1	Disapprove	
Bob Reeping	Allegheny Power	3	Disapprove	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Danny McDaniel	Cleco Power LLC	1	Disapprove	
Bryan Y Harper	Cleco Utility Group	3	Disapprove	

Voter	Entity	Segment	P 1252	Comments
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Daniel Herring	Detroit Edison Co.	4	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	
Dan R.	MRO	10	Disapprove	

Voter	Entity	Segment	P 1252	Comments
Schoenecker				
John Bos	Muscatine Power & Water	3	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Bruce Glorvigen	OTP Wholesale Marketing	6	Disapprove	
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
Tim Hattaway	PowerSouth Energy Cooperative	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Laurie Williams	Public Service Co. of New Mexico	1	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S.	Seminole Electric	6	Disapprove	

Voter	Entity	Segment	P 1252	Comments
Novak	Cooperative, Inc.			
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Jason Shaver	ATC	1	Disapprove	- Load (1-year, 5-year, and 10-year) forecast accuracy can not be reviewed (checked) until 1 year, 5 year, and 10 years later. The accuracy of the different future timeframes are not the same. The 10-year forecast will be much less accurate than the 1-year forecast. The assumptions that can cause large variances in the load forecast (weather, macro economics, micro economic, technology, etc.) may vary widely over 1 year, 5 year , and 10 year timeframes.
Daniel Prowse	Manitoba Hydro	6	Disapprove	: The intent of Requirement R2 is not clear. The load variation threshold is not clear. Is the threshold of 10% simply an example of what load forecast variation could be to trigger forecast improvement, or is it meant to implicitly state that load forecast modification must be made if variation is greater than 10%? 4. Also, The proposed R2 does not consider that there is an inherent randomness in load that cannot be corrected. At that point accuracy can no longer be improved no matter what is done. ... The "shall annually review Load forecast variation" is good, but instead of "if necessary ... modify

Voter	Entity	Segment	P 1252	Comments
				load forecast assumptions" they should say "if accuracy worsens, the cause should be assessed and if possible the model improved."
Gregory Campoli	New York Independent System Operator	2	Disapprove	1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact. 3. The requirement obligates each entity to supply this data to "every other" LSE, PA and RP. This is both unjustified and impractical. 4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other entities have no responsibility for such data. 5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous "normal" hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Finally, since this and the other MOD standards included in this project are predicated upon MOD-016-1 which has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact. 3. The requirement obligates each entity to supply this data to "every other" LSE, PA and RP. This is both

Voter	Entity	Segment	P 1252	Comments
				unjustified and impractical. 4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other entities have no responsibility for such data. 5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous “normal” hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Finally, since this and the other MOD standards included in this project are predicated upon MOD-016-1 which has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. General comment - Each entity’s expertise should be relied upon to gather the appropriate weather information.4. In Requirement R1.5 - What is meant by “biasing of each load forecast”?5. With respect to Requirement R1.5 - Is this applicable to Demand Response?6. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 7. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 8. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.
Kirit S. Shah	Ameren Services	1	Disapprove	All referenced requirements need to explicitely address DSM, or the effect of DSM, on the forecast. The drafting team should clearly define how DSM should be considered, that is as an interruptible load or as a resource.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A.	Louisville Gas and	3	Disapprove	comments will be filed via the formal comment form

Voter	Entity	Segment	P 1252	Comments
Freibert	Electric Co.			
David Murray	PSEG Power LLC	5	Approve	Comments: While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted hourly loads and actual hourly loads as indicated by proposed additions of requirements R1.5 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading. In addition, techniques developed by load forecasting groups to “compare” actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted hourly loads and actual hourly loads as indicated by proposed additions of requirements R1.5 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading.In addition, techniques developed by load forecasting groups to “compare” actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE defers to and supports its RTO organizations (PJM and MISO) regarding the proposed load forecasting changes.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	FE defers to and supports its RTO organizations (PJM and MISO) regarding the proposed load forecasting changes.
Lee Schuster	Florida Power	3	Disapprove	In R2, is the parenthetical statement “(e.g., if variation expressed in terms of error divided by actual

Voter	Entity	Segment	P 1252	Comments
	Corporation			demand is greater than 10%)" a requirement or just a suggestion? It should probably be deleted to avoid confusion.
James Eckelkamp	Progress Energy	6	Disapprove	
Wayne Lewis	Progress Energy Carolinas	5	Disapprove	
Nickesha P Carrol	ConEd of NY	6	Disapprove	In Requirement R2, insert the word "interruptible" between the words "actual demand"
Christopher L de Graffenried	ConEd of NY	1	Disapprove	
Wilket (Jack) Ng	ConEd of NY	5	Disapprove	
Doug Bantam	LES	1	Disapprove	It is unclear if the improved assumptions are to be used for the previous year or the upcoming year. If for the upcoming year, than it must be clearly stated that the responsible entity is to apply last year's assumptions to next year's forecast.
Dennis Florom	LES	5	Disapprove	
Eric Ruskamp	LES	6	Disapprove	
Greg C Parent	Manitoba Hydro	3	Disapprove	o Paragraph 1252: The intent of Requirement R2 is not clear. The load variation threshold is not clear. Is the threshold of 10% simply an example of what load forecast variation could be to trigger forecast improvement, or is it meant to implicitly state that load forecast modification must be made if variation is greater than 10%? 4. Also, The proposed R2 does not consider that there is an inherent randomness in load that cannot be corrected. At that point accuracy can no longer be improved no matter what is done. ... The "shall annually review Load forecast variation" is good, but instead of "if necessary ... modify load forecast assumptions" they should say "if accuracy worsens, the cause should be assessed and if possible the model improved."
John K Loftis	Dominion Virginia Power	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. Some examples are cited below:1. We do not agree that addition of the Transmission Planner, in and of itself, improves or enhances reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads "vary based on temperature and/or humidity" and so should be listed in

Voter	Entity	Segment	P 1252	Comments
				section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads "vary based on temperature and/or humidity" and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.2. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models.3. R2, as written, could decrease reliability by allowing a wider bandwidth before action iscurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
George R. Bartlett	Entergy Corporation	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads "vary based on temperature and/or humidity" and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads "vary based on temperature and/or humidity" and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this
Stanley M Jaskot	Entergy Corporation	5	Disapprove	

Voter	Entity	Segment	P 1252	Comments
				data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models. R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately. While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Russell A Noble	Cowlitz County PUD	3	Disapprove	Placing the example in the requirement, “e.g., if variation expressed in terms of error divided by actual demand is greater than 10%,” does not adequately define what is required to establish a satisfactory trigger for modification of forecast assumptions. It is not clear if an error greater than 10% requires modification of forecasting assumptions, or it is just a suggestion that an acceptable error window should be defined by the entity. The avoidance of prescribing a hard error percentage threshold which would require modification of forecast assumptions is quite correct; Load characteristics along with influencing variables (economy, natural resources, population growth, risk, weather, and etc.) will greatly vary the difficulty range of accurately formulating corresponding Load forecasting assumptions. Many Loads have demand and energy usage that varies greatly (up and down) year to year; therefore a strict comparison of a particular year’s forecast versus the actual can be nothing more than an indication of how well the guessing game was played in adjusting forecasting assumptions. Cowlitz PUD recommends this entire requirement be referred back to the SDT for further study on current practices by entities. Cowlitz PUD also advises that the requirement minus the parenthetical example would be acceptable, and development of a guidance document reflecting the best practices of the industry would be helpful.
Bob Essex	Cowlitz County PUD	5	Disapprove	
Rick Syring	Cowlitz County PUD	4	Disapprove	
David A. Lapinski	Consumers Energy	3	Disapprove	R2 (and therefore VSL 2) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Disapprove	R2 states that as an example, variation expressed in terms of error divided by actual demand is greater than 10%. The 10% threshold is not defined by FERC in its Order and request that a basis be given prior to supporting the proposed changes. Overall R2 does not enhance reliability of the BES.

Voter	Entity	Segment	P 1252	Comments
				R2 states that the applicable entity annually reviews the previous year's load forecast for 10% variation and if necessary modify load forecast assumptions to improve accuracy. It is unclear if the improved assumptions are to be used for the previous year or the upcoming year? If for the upcoming year, than it must be clearly stated that the responsible entity is to apply last year assumptions to next year's forecast.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	R2, as written, would decrease reliability by allowing a wider bandwidth beforeaction is necessary. Also, R2, as written, is un-measurable. We suggest that R2should be given to a standards drafting team to develop appropriately.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
Dana Wheelock	Seattle City Light	3	Disapprove	SCL respectfully votes negative on the proposed requirement #R1.5 and R2 as it relates to the requirement of providing the day-ahead hourly load forecast for each hour and if necessary, modify load forecast assumptions to improve accuracy to within 10%. The standard needs to be clear whether the intent is to create day-ahead hourly load forecasts where every hour has an accuracy of 10% or less, or if it is sufficient, and more realistic, that a percentage of the hourly forecasts for the year be within a certain % of accuracy. Otherwise, the amount of labor and resources to try to improve the accuracy of making sure every hourly load forecast is accurate to within a certain percentage doesn't take into account that it is a forecast, and hourly forecasts sometimes miss their mark, due to changing weather conditions.
Dennis Sismaet	Seattle City Light	6	Disapprove	SCL respectfully votes negative on the proposed requirement #R1.5 and R2 as it relates to the requirement of providing the day-ahead hourly load forecast for each hour and if necessary, modify load forecast assumptions to improve accuracy to within 10%. The standard needs to be clear whether the intent is to create day-ahead hourly load forecasts where every hour has an accuracy of 10% or less, or if it is sufficient, and more realistic, that a percentage of the hourly forecasts for the year be within a certain % of accuracy. Otherwise, the amount of labor and resources to try to improve the accuracy of making sure every hourly load forecast is accurate to within a certain

Voter	Entity	Segment	P 1252	Comments
				percentage doesn't take into account that it is a forecast, and hourly forecasts sometimes miss their mark, due to changing weather conditions.Also, the phrase: "as well as any biasing of each load forecast" should be clarified.
Hao Li	Seattle City Light	4	Disapprove	SCL respectfully votes negative on the proposed requirement #R1.5 and R2 as it relates to the requirement of providing the day-ahead hourly load forecast for each hour and if necessary, modify load forecast assumptions to improve accuracy to within 10%. The standard needs to be clear whether the intent is to create day-ahead hourly load forecasts where every hour has an accuracy of 10% or less, or if it is sufficient, and more realistic, that a percentage of the hourly forecasts for the year be within a certain % of accuracy. Otherwise, the amount of labor and resources to try to improve the accuracy of making sure every hourly load forecast is accurate to within a certain percentage doesn't take into account that it is a forecast, and hourly forecasts sometimes miss their mark, due to changing weather conditions.
Pawel Krupa	Seattle City Light	1	Disapprove	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	See above
Michael F Gildea	Dominion Resources Services	3	Disapprove	See comments to question #25.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
Larry Akens	Tennessee Valley Authority	1	Disapprove	The additon of Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are better able to determine which loads "vary based on temperature and/or humidity" and so should be listed in secton 4, Applicability. Temperature and humidity readings are not well defined, especially over a BA of large geographical area. Requirement 2 as written decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Requirement 1.5 is not clear and needs to be reviewed by a SDT.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in

Voter	Entity	Segment	P 1252	Comments
				section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models. R2, as written, cwould decrease reliability by allowing a wider bandwidth before action is necessarycurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Michelle Rheault	Manitoba Hydro	1	Disapprove	The intent of Requirement R2 is not clear. The load variation threshold is not clear. Is the threshold of 10% simply an example of what load forecast variation could be to trigger forecast improvement, or is it meant to implicitly state that load forecast modification must be made if variation is greater than 10%? 4. Also, The proposed R2 does not consider that there is an inherent randomness in load that cannot be corrected. At that point accuracy can no longer be improved no matter what is done. ... The "shall annually review Load forecast variation" is good, but instead of "if necessary ... modify load forecast assumptions" they should say "if accuracy worsens, the cause should be assessed and if

Voter	Entity	Segment	P 1252	Comments
				possible the model improved."
Scott Peterson	San Diego G&E	3	Disapprove	The language in MOD-019 is too broad in Requirement 2 - a new requirement for this standard. While the purpose of the standard is to focus on a forecast for Demand Response and DCLM, Requirement 2 states forecast without being specific. Second, the requirement also only allows for a 10% variance from forecast to actual, and we believe that in most years we will have a variance beyond the 10%, thus forcing us to develop a method to be closer to our forecast. Assuming that we have a weather anomaly, for which we have NO control, we would be unable to develop a method to stay within the 10% variance. We could also experience an Earthquake, or a fire, both of which will also be beyond our control. In the alternative, we should only have to develop an answer as to WHY our forecast was beyond the 10% variance, and we should not have to develop a method to put us closer to our forecast. We may also want to suggest that NERC is confusing a planning forecast with an operating forecast, which are two separate environments.
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	The proposed changes to MOD-017 to meet FERC directives in paragraphs 1249 - 1255 are complex and do not represent simple changes The existing modifications while attempting to meet the letter of the FERC Orders, is unable to clearly identify all data to meet a specified reliability goal improvement. Neither FERC nor NERC has shown how weather normalizing or reporting biasing will improve reliability. Biasing is vague and undefined. Therefore NERC considered this FERC directive and met its obligation to address a FERC Order. Nothing states that NERC or the industry must accept a vague or undefined FERC directive.
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	The requirement is too prescriptive. Each entity must satisfy itself or correct their assumptions using their own criteria. Prescribing a 10% threshold is not applkicable everywhere.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	The VSL’s should remove the “e.g.” language.
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	

Voter	Entity	Segment	P 1252	Comments
Timothy VanBlaricom	California ISO	2	Disapprove	There are 8760 hours per year in a day ahead hourly forecast, and requiring 8760 error analyses is not practical. Monthly error analyses would look at many months that don't have significance on reliability issues. For R2, weather normalization needs to be addressed. With regard to error divided by actual demand, it is suggested that the error be defined as the absolute value between actual and forecast demand divided by actual demand.
Charles H Yeung	Southwest Power Pool	2	Disapprove	There are several issues with the accuracy proposal:1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact.3. The requirement obligates each entity to supply this data to "every other" LSE, PA and RP. This is both unjustified and impractical.4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other entities have no responsibility for such data.5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous "normal" hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2.
Donald Gilbert	JEA	5	Approve	This is an acceptable requirement provided that modifications to load forecast assumptions may only be redoing an regression analysis with newer historical data. Randomly adjusting assumptions to meet the standard is problematic and could result in lower demand forecast.
Alan Gale	City of Tallahassee	5	Disapprove	This seems that I will be chasing my tail. I have to track hourly peaks and account for inacuracies in the load forecast for temp and humidity and have to analyze it over the year. A single "heat wave" or "cold snap" can skew the peak numbers outside of the "planned" forecast. This will penalilze the entities that estimate high so they can be sure to be doing the right thing in resource acquisition because if I overestimate by 10% I have to modify it to be closer, even if that reduces reliability by

Voter	Entity	Segment	P 1252	Comments
				putting off a resource build. What happens when we revise the forcast down by 15% (to be more accurate) and the economy recovers? We will be mssing short, which is worse.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	Throughout this entire standard it seems as though the terms "demand" and "load" are used interchangeably and terms are capitalized radomly, which appears to be messy. More importantly, regarding the FERC directive, it's seems difficult to report temperature and humidity data across a large entity like an RTO Planning Authority; the humidity/temps vary from one end to the other.
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	United illuminating agrees with the intent but has concerns with the requirement R2. The statement in parenthesis is unclear if NERC is establishing 10% as the allowable variation or not. It's inappropriate to use e.g in a VSL matrix.UI suggests that the entity developing the Load Forecast maintains a document describing the allowable variation and how it is calculated.The Standard requires two Load Forecasts a two year monthly (R1.3) and as requested a five to ten year forecast (R1.4). It is unclear which forecast is being addressed in R2.
Terry L. Blackwell	Santee Cooper	1	Disapprove	We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We disagree with R2 that is intended to address the directives in paragraph 1252 and 1255. An LSE is constantly updating and tuning their load forecast model and cannot tolerate a load forecast error anywhere close to 10%. If an LSE only reviewed their load forecast annually and adjusted the inputs if the error exceeded 10%, there are many days each year that the LSE would likely not serve load. This requirement represents a significant reduction in reliability. A group of load forecasting experts needs to be convened in a drafting team to address this directive.
Kim Warren	IESO	2	Disapprove	We question the basis for the 10% error if used as a threshold for R2. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Further, the 10% threshold seems loose. Is it in effect saying that the responsible entity should review it forecasting process on an annual basis? Sometimes an error of 10% is totally explainable and should not warrant a change in forecast methodology (this is especially true for long term forecasts where weather is uncertain). It is prudent to review the methodology but to change it for changes sake is not.
Jeffrey	PSE&G	3	Approve	While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM

Voter	Entity	Segment	P 1252	Comments
Mueller				in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	While the PSEG Companies are voting to approve, PSEG Companies believe that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error.
Saurabh Saksena	National Grid	1	Disapprove	With respect to Requirement R2.0 - Remove the wording in the parentheses. Also, delete it from the VSL.
John C. Collins	Platte River Power Authority	1	Approve	Yes, but add comment that clarity is needed. 10% variation of hourly? Day-ahead? Or just for monthly and annual?
Terry L Baker	Platte River Power Authority	3	Approve	Yes, but clarity is needed. 10% variation of hourly? Day-ahead? Or just for monthly and annual?

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Raj Rana	AEP	3	In Favor	
Edward P. Cox	AEP Marketing	6	In Favor	
Brock Ondayko	AEP Service Corp.	5	In Favor	
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Francis J. Halpin	Bonneville Power Administration	5	In Favor	
Rebecca Berdahl	Bonneville Power Administration	3	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Randall McCamish	City of Vero Beach	1	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Walter Yeager	Duke Energy Carolina	6	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Thomas W. Richards	Fort Pierce Utilities Authority	4	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Donald Gilbert	JEA	5	In Favor	
Larry E Watt	Lakeland Electric	1	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	In Favor	
John Bos	Muscatine Power &	3	In Favor	

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
	Water			
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
David T. Anderson	Ocala Electric Utility	3	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Terri Pyle	Oklahoma Municipal Power Authority	4	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Bethany Wright	SMUD	5	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Mike Ramirez	SMUD	4	In Favor	
Tim Kelley	SMUD	1	In Favor	
Richard	South Carolina	5	In Favor	

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Jones	Electric & Gas Co.			
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
Jeff Nelson	Springfield Utility Board	3	In Favor	
RJames Rocha	Tampa Electric Co.	5	In Favor	
Ronald L Donahey	Tampa Electric Co.	3	In Favor	
Brandy A Dunn	Western Area Power Administration	1	In Favor	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Rodney Phillips	Allegheny Power	1	Opposed	
Bob Reeping	Allegheny Power	3	Opposed	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
Daniel Herring	Detroit Edison Co.	4	Opposed	

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Robert Smith	Duke Energy	5	Opposed	
Douglas E. Hils	Duke Energy Carolina	1	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
George R. Bartlett	Entergy Corporation	1	Opposed	
Stanley M Jaskot	Entergy Corporation	5	Opposed	
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Bruce Glorvigen	OTP Wholesale Marketing	6	Opposed	
Tim Hattaway	PowerSouth Energy Cooperative	5	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A. Heimbach	PPL Generation LLC	5	Opposed	
James Eckelkamp	Progress Energy	6	Opposed	
Wayne Lewis	Progress Energy Carolinas	5	Opposed	

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Laurie Williams	Public Service Co. of New Mexico	1	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	
Terry L. Blackwell	Santee Cooper	1	Opposed	
Dana Wheelock	Seattle City Light	3	Opposed	
Hao Li	Seattle City Light	4	Opposed	
Pawel Krupa	Seattle City Light	1	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	
Richard McLeon	South Texas Electric Cooperative	1	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
George T. Ballew	Tennessee Valley Authority	5	Opposed	

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Jonathan Appelbaum	United Illuminating Co.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact. 3. The requirement obligates each entity to supply this data to “every other” LSE, PA and RP. This is both unjustified and impractical. 4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other entities have no responsibility for such data. 5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous “normal” hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Finally, since this and the other MOD standards included in this project are predicated upon MOD-016-1 which has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
John Tolo	Tucson Electric	1	In Favor	Assume that Q. 32 should state Paragraph 1252?

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
	Power Co.			
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 1251 in their current format, we cannot support the changes to the VSLs.
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Louise McCarren	Western Electricity Coordinating Council	10	In Favor	I am in favor of the revised VSLs for R2. However I believe that Question 32 incorrectly references Paragraph 1250 and should have referenced Paragraph 1252.
Brad Jones	Luminant Energy	6	Opposed	No opinion
Alan Gale	City of Tallahassee	5	Opposed	No VRF for R1. R2 is OK. R2 VSL change "improvements" to "adjustments".
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.
Bob Essex	Cowlitz County PUD	5	Opposed	Pinning down when an entity has “failed to make improvements to improve accuracy when such improvements were necessary (e.g., variation was greater than 10%)” may be a very difficult audit task. Consider a hypothetical case where an entity has modified Load forecast assumptions each year over a 6-year period in an effort to improve accuracy. However, two consecutive year’s variation is much greater than 10%; has the entity “failed to make improvements” as “necessary?” Should a violation be assessed? Cowlitz PUD suggests the following verbiage: The responsible entity reviewed its Load forecast accuracy on an annual basis, but failed to make any effort to improve accuracy.
Russell A Noble	Cowlitz County PUD	3	Opposed	Pinning down when an entity has “failed to make improvements to improve accuracy when such improvements were necessary (e.g., variation was greater than 10%)” may be a very difficult audit task. Consider a hypothetical case where an entity has modified Load forecast assumptions each year over a 6-year period in an effort to improve accuracy. However, two consecutive year’s variation is much greater than 10%; has the entity “failed to make improvements” as “necessary?” Should a violation be assessed? Cowlitz PUD suggests the following verbiage: The responsible entity reviewed its Load forecast accuracy on an annual basis, but failed to make any effort to improve accuracy.

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Rick Syring	Cowlitz County PUD	4	Opposed	Pinning down when an entity has "failed to make improvements to improve accuracy when such improvements were necessary (e.g., variation was greater than 10%)" may be a very difficult audit task. Consider a hypothetical case where an entity has modified Load forecast assumptions each year over a 6-year period in an effort to improve accuracy. However, two consecutive year's variation is much greater than 10%; has the entity "failed to make improvements" as "necessary?" Should a violation be assessed? Cowlitz PUD suggests the following verbiage: The responsible entity reviewed its Load forecast accuracy on an annual basis, but failed to make any effort to improve accuracy.
David A. Lapinski	Consumers Energy	3	Opposed	R2 (and therefore VSL 2) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
David Frank Ronk	Consumers Energy	4	Opposed	R2 (and therefore VSL 2) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
James B Lewis	Consumers Energy	5	Opposed	R2 (and therefore VSL 2) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
Kim Warren	IESO	2	Opposed	R2 needs to be changed first.
Charles Locke	Kansas City Power & Light Co.	3	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
Michael Gammon	Kansas City Power & Light Co.	1	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
Gregg R Griffin	City of Green Cove Springs	3	In Favor	replace "improvements" with "adjustments"

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Dennis Sismaet	Seattle City Light	6	Opposed	SCL respectfully votes negative on the proposed requirement #R1.5 and R2 as it relates to the requirement of providing the day-ahead hourly load forecast for each hour and if necessary, modify load forecast assumptions to improve accuracy to within 10%. The standard needs to be clear whether the intent is to create day-ahead hourly load forecasts where every hour has an accuracy of 10% or less, or if it is sufficient, and more realistic, that a percentage of the hourly forecasts for the year be within a certain % of accuracy. Otherwise, the amount of labor and resources to try to improve the accuracy of making sure every hourly load forecast is accurate to within a certain percentage doesn't take into account that it is a forecast, and hourly forecasts sometimes miss their mark, due to changing weather conditions.Also, the phrase: "as well as any biasing of each load forecast" should be clarified.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Opposed	See above
Saurabh Saksena	National Grid	1	Opposed	See comments above.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Opposed	The inclusion of VRFs and VSL's to versions of standards that do not have them should be fully vetted by the industry.
Rex A Roehl	Indeck Energy Services, Inc.	5	Opposed	The R2 VSL's should be Lower and Moderate instead of High and Severe. The reliability impact of this inaccuracy is hardly measurable.
Harold Taylor, II	GTC	1	Opposed	The VSL’s should remove the “e.g.” language.
Guy Andrews	Georgia System Operations Corporation	4	Opposed	The VSL's should remove the "e.g." language.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	The VSL's should remove the "e.g." language.
Frank Gaffney	Florida Municipal Power Agency	4	In Favor	Wording is awkward on "High" VSL, consider replacing "improvements" with "adjustments"

Voter	Entity	Segment	P 1252 VRF and VSLs	Comments
Walt Gill	Lake Worth Utilities	1	In Favor	Wording is awkward on "High" VSL, consider replacing "improvements" with "adjustments"
John C. Collins	Platte River Power Authority	1	In Favor	Yes, but add comment that clarity is needed. 10% variation of hourly? Day-ahead? Or just for monthly and annual? (NOTE:Question 32 appears to incorrectly reference paragraph 1250. It appears it should be referencing paragraph 1252)
Terry L Baker	Platte River Power Authority	3	In Favor	Yes, but clarity is needed. 10% variation of hourly? Day-ahead? Or just for monthly and annual? NOTE:Question 32 appears to incorrectly reference paragraph 1250. It appears it should be referencing paragraph 1252)
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P1255:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1255	Comments
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Abstain	
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Danny McDaniel	Cleco Power LLC	1	Abstain	
Bryan Y Harper	Cleco Utility Group	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	

Voter	Entity	Segment	P 1255	Comments
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Robert Smith	Duke Energy	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	

Voter	Entity	Segment	P 1255	Comments
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Tim Hattaway	PowerSouth Energy Cooperative	5	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	

Voter	Entity	Segment	P 1255	Comments
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
Jason Shaver	ATC	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S.	Bonneville Power	1	Approve	

Voter	Entity	Segment	P 1255	Comments
Watkins	Administration			
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
Brian Conroy	Central Maine Power Co.	1	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	

Voter	Entity	Segment	P 1255	Comments
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	
Kenneth Dresner	FirstEnergy Solutions	5	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Lee Schuster	Florida Power	3	Approve	

Voter	Entity	Segment	P 1255	Comments
	Corporation			
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Harold Taylor, II	GTC	1	Approve	
Kathleen Goodman	ISO New England, Inc.	2	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Approve	
Charlie Martin	Louisville Gas and Electric Co.	5	Approve	
Daryn Barker	Louisville Gas and Electric Co.	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	

Voter	Entity	Segment	P 1255	Comments
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
David H. Boguslawski	Northeast Utilities	1	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	

Voter	Entity	Segment	P 1255	Comments
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	

Voter	Entity	Segment	P 1255	Comments
Brenda L Truhe	PPL Electric Utilities Corp.	1	Approve	
Mark A. Heimbach	PPL Generation LLC	5	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T.	Salt River Project	3	Approve	

Voter	Entity	Segment	P 1255	Comments
Underhill				
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Steve McElhaney	South Mississippi Electric Power Association	4	Approve	
Jerry W Johnson	South Mississippi Electric Power Association	5	Approve	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	

Voter	Entity	Segment	P 1255	Comments
Scott M. Helyer	Tenaska, Inc.	5	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	

Voter	Entity	Segment	P 1255	Comments
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Laurie Williams	Public Service Co. of New Mexico	1	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	

Voter	Entity	Segment	P 1255	Comments
Gregory Campoli	New York Independent System Operator	2	Disapprove	1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact. 3. The requirement obligates each entity to supply this data to "every other" LSE, PA and RP. This is both unjustified and impractical. 4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other entities have no responsibility for such data. 5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous "normal" hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Finally, since this and the other MOD standards included in this project are predicated upon MOD-016-1 which has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact. 3. The requirement obligates each entity to supply this data to "every other" LSE, PA and RP. This is both unjustified and impractical. 4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other

Voter	Entity	Segment	P 1255	Comments
				entities have no responsibility for such data. 5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous “normal” hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Finally, since this and the other MOD standards included in this project are predicated upon MOD-016-1 which has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	Addition of responsible entities is not low hanging fruit.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	All referenced requirements need to explicitely address DSM, or the effect of DSM, on the forecast. The drafting team should clearly define how DSM should be considered, that is as an interruptible load or as a resource.
David Murray	PSEG Power LLC	5	Approve	Comments: While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted hourly loads and actual hourly loads as indicated by proposed additions of requirements R1.5 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading. In addition, techniques developed by load forecasting groups to “compare” actual data to forecasted data will be subjective

Voter	Entity	Segment	P 1255	Comments
				and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted hourly loads and actual hourly loads as indicated by proposed additions of requirements R1.5 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading.In addition, techniques developed by load forecasting groups to “compare” actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	For an entity that covers a diverse area, it is unclear where the temperature and humidity readings are to be taken, or if many (how many?) readings are to be averaged. And why does the entity that has a variation on temperature but not humidity, still need to report humidity?
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	In M1, replace "load data" with "demand data" and restore "per". What about the error data from 1.5, should that be included here in the measurements?
Saurabh Saksena	National Grid	1	Disapprove	National Grid believes that the Planning Authority has the authority to collect information and hence the information collection should be retained at the level of Planning Authority and not include Transmission Planner.
John K Loftis	Dominion Virginia Power	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. Some examples are cited below:1. We do not agree that addition of the Transmission Planner, in and of itself, improves or enhances reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage

Voter	Entity	Segment	P 1255	Comments
				addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.2. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models.3. R2, as written, could decrease reliability by allowing a wider bandwidth before action iscurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
George R. Bartlett	Entergy Corporation	1	Disapprove	Paragraphs 1249-1255 - While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their models. R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately. While we agree that the
Stanley M Jaskot	Entergy Corporation	5	Disapprove	

Voter	Entity	Segment	P 1255	Comments
				changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	See above
Michael F Gildea	Dominion Resources Services	3	Disapprove	See comments to question #25.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
Larry Akens	Tennessee Valley Authority	1	Disapprove	The additon of Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are better able to determine which loads "vary based on temperature and/or humidity" and so should be listed in secton 4, Applicability. Temperature and humidity readings are not well defined, especially over a BA of large geographical area. Requirement 2 as written decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Requirement 1.5 is not clear and needs to be reviewed by a SDT.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) meter usage and therefore are best able to determine which loads “vary based on temperature and/or humidity” and so should be listed in section 4: Applicability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. If the SDT chooses to retain Transmission Planner in the applicability section, we STRONGLY encourage addition of Facility owners (Transmission Owner and Distribution Provider and possibly Load Serving Entity) accompanied by additional requirements that these entities identify which loads “vary based on temperature and/or humidity” and require them to provide coincident hourly

Voter	Entity	Segment	P 1255	Comments
				temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner. Temperature and humidity readings are not well defined over a large BA. Each BA would likely use a slightly different methodology to capture this data, resulting in a non-homogenous dataset. These values are available from commercial services and FERC/NERC/Regional entities could specify the data they needed from the commercial services for their respective (and likely differing)models. R2, as written, cwould decrease reliability by allowing a wider bandwidth before action is necessarycurrently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.
Alan Gale	City of Tallahassee	5	Disapprove	The Transmission Planner should be planning to serve the forecasted load with certain margins. They should not be creating the actual load forecasts. The Load Forecast should be provided by the LSE (or BA using LSE data).
Charles H Yeung	Southwest Power Pool	2	Disapprove	There are several issues with the accuracy proposal:1. FERC states that it does want a requirement to correct load forecast inaccuracies, but does not provide any clarity as to which data (local, wide area, both) is to be analyzed and what reliability purpose is addressed. Such questions are best vetted within the NERC Reliability Standards Development Procedures when and if there is a cited need. 2. As to who should report these loads, it states that every LSE, PA, TP, and RP should submit this data for NERC validation. There is no identification of how and why this much data is needed. On a superficial level it makes sense that all data be verified and made as correct as possible. But from a pragmatic perspective such a mandate is a useless exercise in data management and will have no identifiable reliability impact.3. The requirement obligates each entity to supply this data to “every other” LSE, PA and RP. This is both unjustified and impractical.4. The new R1.5 requires planners to provide hourly day-ahead load forecasting accuracy data. Except for the LSEs who may provide day ahead forecasts, the other entities have no responsibility for such data.5. The new R2 is unclear. There seems to be no reliability based justification for after-the-fact modification of load assumptions just because one or more hourly values exceed a 10% forecasting error; in fact such adjustments for spurious hourly data would likely result in erroneous “normal” hour data. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do

Voter	Entity	Segment	P 1255	Comments
				not agree with the changes to the VSLs for R1 and R2.
Donald Gilbert	JEA	5	Approve	This is acceptable recognizing that the Transmission Planner's only role in forecasting generator loading requirements is to add the transmission system losses to the LSE's load forecast. The transmission planner should not be obligated to perform their own load forecast.
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	Transmission planners should not be responsible for load forecasting and hence should not be applicable to this standard.
Randall McCamish	City of Vero Beach	1	Disapprove	Transmission Planners should not be responsible for load forecasting and hence should not be applicable to this standard. Transmission Planners simply gather the load forecasts of the entities responsible for load forecasting within their planning area. In essence, a Transmission Planner will be dependent on the compliance of the entities within its planning area to remain compliant. If that is the case, then, there should be multiple requirements making entities within the planning area report load forecasts to the Transmission Planner before the Transmission Planner is enabled to report a load forecast to the region. This additional layer of administrative burden makes no sense. If Transmission Planners develop different, independent load forecasts, which ones will be used in the regional analyses? Those provided by the TPs, or the aggregate of those provided by other entities within the TPs planning area? The FERC directive can probably be addressed through a requirement of the Region to break out the regional load forecast by each Transmission Planning area
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	Transmission Planners should not be responsible for load forecasting and therefore, this standard should not include them in the applicability. Transmission Planners simply gather load forecasts from the entities responsible for load forecasting within their planned area.
Terry L. Blackwell	Santee Cooper	1	Disapprove	We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We disagree with R2 that is intended to address the directives in paragraph 1252 and 1255. An LSE is constantly updating and tuning their load forecast model and cannot tolerate a load forecast error anywhere close to 10%. If an LSE only reviewed their load forecast annually and adjusted the inputs if the error exceeded 10%, there are many days each year that the LSE would likely not serve load. This requirement represents a significant reduction in reliability. A group of load forecasting experts needs to be convened in a drafting team to address this directive.
Kim Warren	IESO	2	Disapprove	we question the basis for the 10% error if used as a threshold for R2. However, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumption even at an error greater than 10%. Standards cannot be written with loose

Voter	Entity	Segment	P 1255	Comments
				language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Further, the 10% threshold seems loose. Is it in effect saying that the responsible entity should review it forecasting process on an annual basis? Sometimes an error of 10% is totally explainable and should not warrant a change in forecast methodology (this is especially true for long term forecasts where weather is uncertain). It is prudent to review the methodology but to change it for changes sake is not.
Jeffrey Mueller	PSE&G	3	Approve	While the PSEG Companies are voting to approve, PSEG believes that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	While the PSEG Companies are voting to approve, PSEG Companies believe that the concerns expressed by PJM in its comments should be carefully considered and clarifications and/or further language changes proposed as appropriate.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	While we agree that the changes address the cited FERC directives, we believethat addition of the Transmission Planner does not improve or enhance reliability.Pursuant to the NERC Functional Model, the Transmission Planner performs thefollowing:Coordinates and collects data for system modeling from Load-ServingEntities, Generator Owners, Distribution Providers, other Transmission Planners,Transmission Owners, and Transmission Service Providers. Such data includes -Demand and energy forecasts, capacity resources, and demand responseprograms from Load-Serving Entities, and Resource Planners.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	While we agree that the changes address the cited FERC directives, we believe that addition of the Transmission Planner does not improve or enhance reliability. Pursuant to the NERC Functional Model, the Transmission Planner performs the following: Coordinates and collects data for system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, other Transmission Planners, Transmission Owners, and Transmission Service Providers. Such data includes - Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners.

Summary Consideration for changes related to P1276:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1276	Comments
Allen Mosher	American Public Power Association	4	Abstain	
Jason Shaver	ATC	1	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Alan Gale	City of Tallahassee	5	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Robert Smith	Duke Energy	5	Abstain	
Dan	Dynegy Inc.	5	Abstain	

Voter	Entity	Segment	P 1276	Comments
Roethemeyer				
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
Robert Mattey	Ohio Valley Electric Corp.	1	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret	Pacific Northwest	8	Abstain	

Voter	Entity	Segment	P 1276	Comments
Ryan	Generating Cooperative			
Ronald Schloendorn	PECO Energy	1	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Raj Rana	AEP	3	Approve	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L.	AESO	2	Approve	

Voter	Entity	Segment	P 1276	Comments
Murray				
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
Daniel	Detroit Edison Co.	4	Approve	

Voter	Entity	Segment	P 1276	Comments
Herring				
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Harold Taylor, II	GTC	1	Approve	
Kim Warren	IESO	2	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis	LES	5	Approve	

Voter	Entity	Segment	P 1276	Comments
Florom				
Eric Ruskamp	LES	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Steven Grego	MEAG Power	3	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Dan R. Schoenecker	MRO	10	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	

Voter	Entity	Segment	P 1276	Comments
Stacie Hebert	Otter Tail Power Co.	5	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Tim Hattaway	PowerSouth Energy Cooperative	5	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade	6	Approve	

Voter	Entity	Segment	P 1276	Comments
	LLC			
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana	Seattle City Light	3	Approve	

Voter	Entity	Segment	P 1276	Comments
Wheelock				
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-Kendall	SMUD	3	Approve	
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Disapprove	

Voter	Entity	Segment	P 1276	Comments
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	

Voter	Entity	Segment	P 1276	Comments
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	

Voter	Entity	Segment	P 1276	Comments
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	"as requested" in R1.1 should be moved up to R1 in order to cover all the sub-requirements. This is a key term in the compliance arena.
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. General comment - In the "NERC Comments" section, remove the "Section B" descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. With respect to Requirement R1.2 - How about simply 'Summer and winter peak actual and weather corrected peak if observed, forecast load (one year ahead).' This requires provision of the weather corrected actual which is directly comparable to the forecast. What is meant by "biasing of each load forecast"?4. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 5. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 6. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	Adding sub-requirements R1.1 and R1.2 does not comport with the formatthat NERC notified the Commission it would use in standards development goingforward. NERC submitted the informational filing on August 10, 2009, inresponse, to the Commission's ruling in Order 722. Specifically, the proposaleliminates the use of sub-requirements and proposes to use a numbered orbulleted list
Anthony L Wilson	Georgia Power Co.	3	Disapprove	

Voter	Entity	Segment	P 1276	Comments
Gwen S Frazier	Gulf Power Co.	3	Disapprove	based on the characteristics of the list.
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	
David A. Lapinski	Consumers Energy	3	Disapprove	As written, R1.2 and R2 apply to peak Load. They should apply Interruptible Demands and Direct Control Load Management, the subject of this standard. As is, they essentially duplicate the requirements of R1.5 and R2 of draft MOD-017. In R1.5 the term "peak Forecast variation" is not clear. Is this intended to be the difference between forecast and actual demand?
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Mel Jensen	APS	5	Disapprove	AZPS agrees that the changes to R1 address Paragraph 1276 in Order 693. However, during the change process NERC has changed R1 to have sub-requirements R1.1 and R1.2. In doing so NERC has changed the meaning of R1. Prior to the change, R1 stated that annually as requested. Now the Standard states that the information shall be provided annually, yet R1.1 states as requested. This should be clarified to remove any confusion.
Robert D Smith	Arizona Public Service Co.	1	Disapprove	
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	Do not agree with the concept of developing an indices that indicates the "accuracy, error and bias" between forecasted loads and actual loads as indicated by proposed additions of requirements R1.2 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to "normalize" actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different "latent heat" or "latent cold" build-ups. Poor indications of load accuracy are of no value and can be misleading. In addition, techniques developed by load
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	

Voter	Entity	Segment	P 1276	Comments
				forecasting groups to "compare" actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit. It is inappropriate to include Regional Entities as an entity to provide forecasted load data. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain forecasted load information as defined in this Standard MOD-019. See definition below: Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE defers to and supports its RTO organizations (PJM and MISO) regarding the proposed load forecasting changes.
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	FE defers to and supports its RTO organizations (PJM and MISO) regarding the proposed load forecasting changes.
Timothy VanBlaricom	California ISO	2	Disapprove	For California ISO, interruptible demand and direct control load is a required program under the jurisdiction of the California PUC. It's a subscription for those who want to participate in the program. The CPUC counts the interruptible demand and direct control load as a resource and, as such, is not forecasted in the manner that load is. System need determines whether this resource is called upon and in most years only portions of the programs are call on, so there is no "actual" amount to do an error analysis against, nor to do an error analysis of the program.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	How is this to be accomplished? Industry still has questions on how to adequately do this without introducing additional error. This is not a simple request/task.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	In general the wording is confusing. Measuring accuracy of interruptible demands in R2 could be a problem if these loads are not interrupted.
Charles H Yeung	Southwest Power Pool	2	Disapprove	In the context of the details of the requirement, the proposed R1 changes raise issues regarding: the lack of clarity in definition of what DCLM is; what biases (see R1.2) it wants and who needs what information for reliability. The SAR requestor does not recognize the fact that the ERO has recognized

Voter	Entity	Segment	P 1276	Comments
				the complexity associated with this area by initiating a Demand Resource Team.
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	No meaning given to "biasing forecast."
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Greg C Parent	Manitoba Hydro	3	Disapprove	o 1276 - See comments regarding R1.2's "biasing" and R2's "modify load forecast assumptions" given in MOD-017
Wilket (Jack) Ng	ConEd of NY	5	Disapprove	On Requirement R1.2, please clarify the term “biasing.” Insert words “the weather adjusted” or “weather normalized” following the words “divided by.” The forecast and actual should be on the same basis.
Michael F Gildea	Dominion Resources Services	3	Disapprove	Paragraphs 1276 - 1277 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. 1. R1.5 - The language needs to be more specific as to which ‘version’ of the load forecast is to be compared to actual. Most entities forecast load for any given day at multiple intervals. As example DVP forecasts load for the future 7 days when weather forecast is updated (typically 0400, 1100, and 1600). Weather forecasts are also updated whenever the vendor determines a significant change from previous forecast occurs. This also triggers our load forecast software to produce an updated load forecast. During the actual day, the current day load forecast is updated each hour (for the remaining hours of the day) based upon preliminary ‘actual load’ for the preceding hour as well as any changes to the weather forecast for the current day.2. R2, as written, could decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
John K Loftis	Dominion Virginia Power	1	Disapprove	
Jeff Nelson	Springfield Utility Board	3	Disapprove	Please refer to SUB's comment form
Bob Essex	Cowlitz County PUD	5	Disapprove	R1 and R1.1 are acceptable. However, R1.2 needs to clarify what is meant by “Forecast” (capitalized and not defined); suggest the following verbiage: Summer and winter peak forecast variation of interruptible demands and DCLM for the previous year, expressed in terms of error divided by actual demand, as well as any biasing of each forecast.
Russell A Noble	Cowlitz County PUD	3	Disapprove	
Rick Syring	Cowlitz County	4	Disapprove	

Voter	Entity	Segment	P 1276	Comments
	PUD			
Kirit S. Shah	Ameren Services	1	Disapprove	R1.1 - Add ",DSM," after interruptible demands
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Disapprove	R1.2. The language used for this requirement is unclear. PG&E recommends the following language be used to meet the intent of the Federal Energy Regulatory Commission Order 693:"Summer and winter peak forecast variation of interruptible demands and DCLM for the previous year, expressed in terms of the difference between the forecast and actual amount of interruptible demands and DCLM divided by the forecasted amount of interruptible demands and DCLM for the previous year, accounting for differences in forecast versus operating conditions when the interruptible demands and DCLM were operated, as well as any biasing of each forecast of interruptible demands and DCLM."This language is significantly more precise in the actual information to be supplied and explicitly accounts for differences between planning forecasts and operational results that are caused by differences in environmental and other operational conditions that could not be accounted for during a planning forecast. PG&E is assuming that the Order 693 intended the variation to be measured against the forecasted DR and not forecasted total load. The prior version was ambiguous on this point.
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	R2 = actually implement DCLM and compare that to a similair hour whre DCLM in not implemented to calculate the actual ammount and extrapolate the value to peak load..
Saurabh Saksena	National Grid	1	Disapprove	Requirement R1.2 should not be in this standard based on the title of the standard. The standard deals with interruptible demand and DCLM data and requirement R1.2 is more about load forecasting. National Grid suggests deleting R1.2. R1.2 can find place in MOD_17 standard.
Christopher L de Graffenried	ConEd of NY	1	Disapprove	Requirement R1.2: Please clarify term "biasing." Insert words "the weather adjusted" or "weather normalized" following the words "divided by." The forecast and actual should be on the same basis.
Peter T Yost	ConEd of NY	3	Disapprove	Requirement R1.2: Please clarify term "biasing." Insert words "the weather adjusted" or "weather normalized" following the words "divided by." The forecast and actual should be on the same basis.
Nickesha P Carrol	ConEd of NY	6	Disapprove	
George T. Ballew	Tennessee Valley Authority	5	Disapprove	Requirements 1.2 and 2 are not in scope for this standard.
Larry Akens	Tennessee Valley Authority	1	Disapprove	Requirements 1.2 and 2 are not in scope for this standard. Additional requirements do not enhance reliability.

Voter	Entity	Segment	P 1276	Comments
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	We suggest that R1.2 and R2 are not in scope for this standard. While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Daniel Prowse	Manitoba Hydro	6	Disapprove	See comments regarding R1.2's "biasing" and R2's "modify load forecast assumptions" given in MOD-017
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	Short term forecasts can vary from actuals by more than 10% due to uncontrollable weather and long term forecasts can vary from actuals due to unforeseen economic conditions such as the 2008 / 2009 recessions. A zero DSM period when DSM is not used compared to any value is more than a 10% variation. Further DSM can be a very small portion of an overall forecast. Mandating a correction and applying a high VSL to future forecasts for events beyond an entity's control, i.e when an entity "failed to make improvements to improve accuracy", is wrong and unrealistic and could lead to unjustified penalties. MidAmerican objects to the use of "error" in these revisions because while this is the statistical term it does not describe the true nature of the variation in load forecasting. It could be that variation in explanatory variables would indicate that there is "error" in the forecast if it matched exactly the actuals in that case. MidAmerican recommends that "error" in every case be replaced by "variation" or some other words like "the differences between the forecasts and actuals". Finally to penalize for variations is wrong. The penalties should relate to improper development of forecasts. Failure to consider weather when making forecasts when there are weather related loads is an example.The existing modifications while attempting to meet the letter of the FERC Orders, does not improve reliability and will likely have unintended consequences and may reduce system reliability. Neither FERC nor NERC has shown a technical basis or justification of the benefits to enforcing corrections to a potentially small portion of a forecast. Therefore NERC has considered this FERC directive, and met its obligation to address a FERC Order. Nothing states that NERC or the industry must accept a vague or undefined FERC directive.By rushing policy making, taking utility industry control of VRF / VSLs away, raising VRF / VSLs to high levels, and potentially enforcing massive penalties for any violation, regulators have forced entities to look at each word and consider the worst possible outcome, making standards development more difficult. FERC, NERC, and the industry should return to the collaborate standards making process that emphasizes education over enforcement.
Gregory	New York	2	Disapprove	Taken in isolation the general nature of the proposed change to R1 is appropriate. In the context

Voter	Entity	Segment	P 1276	Comments
Campoli	Independent System Operator			of the details of the requirement, the proposed R1 changes raise issues regarding: the lack of clarity in definition of what DCLM is; what biases (see R1.2) it wants and who needs what information for reliability. The SAR requestor does not recognize the fact that the ERO has recognized the complexity associated with this area by initiating a Demand Resource Team. The question is "what is the reliability-need to analyze LSE load data when the PA's data is the only relevant data for use in Planning Assessments"? Localized modeling may also use localized loads but that would be on a bus load basis not on an entity basis.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Bob C. Thomas	Illinois Municipal Electric Agency	4	Disapprove	The original inclination was to approve these changes in support of NERC's objectives to expedite attention to certain Order 693 Directives; however, from interaction with colleagues in the industry there appears to be sufficient concern/confusion about how an entity would comply with the proposed revisions that additional vetting is appropriate.
Randall McCamish	City of Vero Beach	1	Disapprove	This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	
Donald Gilbert	JEA	5	Approve	This is acceptable if the different entities are only responsible for reporting and validating the interruptible and DCLM utilized in their respective processes i.e. if the Transmission Planner does not utilize interruptible and DCLM in remedial actions, then there is no obligation to determine interruptible and DCLM. Even if they did utilize, the LSE should be identifying the distribution of interruptible and DCLM under different seasonal conditions across the LSE service points for the Transmission Planner.
Danny McDaniel	Cleco Power LLC	1	Disapprove	This will require an entity to review its Load forecast accuracy and adjust to within 10%. What is the basis for the 10% variation?

Voter	Entity	Segment	P 1276	Comments
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Terry L. Blackwell	Santee Cooper	1	Disapprove	We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We do not believe that the directives in paragraph 1276 and 1277 represent low hanging fruit that can be accomplished by this ad hoc and expedited SAR. We believe the Commission likely would have the same view given their use of "innovative solutions" in their directive in paragraph 1276. Innovation takes time. Clearly, a group of experts needs to be convened in a drafting team to address this Commission directive. We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce reliability. Adding sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
George R. Bartlett	Entergy Corporation	1	Disapprove	While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	

Summary Consideration for changes related to P1277:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1277	Comments
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Alan Gale	City of Tallahassee	5	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	
Brenda Powell	Constellation Energy Commodities	6	Abstain	

Voter	Entity	Segment	P 1277	Comments
	Group			
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Robert Smith	Duke Energy	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
Robert	Ohio Valley Electric	1	Abstain	

Voter	Entity	Segment	P 1277	Comments
Mattey	Corp.			
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	

Voter	Entity	Segment	P 1277	Comments
Jason L. Murray	AESO	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	

Voter	Entity	Segment	P 1277	Comments
Daniel Herring	Detroit Edison Co.	4	Approve	
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Steven Grego	MEAG Power	3	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	

Voter	Entity	Segment	P 1277	Comments
Jerome Murray	Oregon Public Utility Commission	9	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Tim Hattaway	PowerSouth Energy Cooperative	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
Kenneth D. Brown	PSE&G	1	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R.	Public Utility	3	Approve	

Voter	Entity	Segment	P 1277	Comments
Johnson	District No. 1 of Chelan County			
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Bethany Wright	SMUD	5	Approve	
James Leigh-	SMUD	3	Approve	

Voter	Entity	Segment	P 1277	Comments
Kendall				
Mike Ramirez	SMUD	4	Approve	
Tim Kelley	SMUD	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Disapprove	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	

Voter	Entity	Segment	P 1277	Comments
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	
Dan R. Schoenecker	MRO	10	Disapprove	
Michael	Niagara Mohawk	3	Disapprove	

Voter	Entity	Segment	P 1277	Comments
Schiavone	(National Grid Co.)			
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Bruce Glorvigen	OTP Wholesale Marketing	6	Disapprove	
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power	5	Disapprove	

Voter	Entity	Segment	P 1277	Comments
	Association			
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Bob Essex	Cowlitz County PUD	5	Disapprove	“Load forecast variation” does not parallel requirement R1; it is not clear if R2 is referencing back to forecasts of interruptible demands and DCLM. Further, placing the example in the requirement, “e.g., if variation expressed in terms of error divided by actual demand is greater than 10%,” does not adequately define what is required to establish a satisfactory trigger for modification of forecast assumptions. It is not clear if an error greater than 10% requires modification of forecasting assumptions, or it is just a suggestion that an acceptable error window should be defined by the entity. The avoidance of prescribing a hard error percentage threshold which would require modification of forecast assumptions is quite correct; Load characteristics along with influencing variables (economy, natural resources, population growth, risk, weather, and etc.) will greatly vary the difficulty range of accurately formulating corresponding Load forecasting assumptions. Many Loads have demand and energy usage that varies greatly (up and down) year to year; therefore a strict comparison of a particular year’s forecast versus the actual can be nothing more than an indication of how well the guessing game was played in adjusting forecasting assumptions. Cowlitz
Russell A Noble	Cowlitz County PUD	3	Disapprove	
Rick Syring	Cowlitz County PUD	4	Disapprove	

Voter	Entity	Segment	P 1277	Comments
				PUD recommends this entire requirement be referred back to the SDT for further study on current practices by entities. Cowlitz PUD also advises that the requirement minus the parenthetical example would be acceptable, and development of a guidance document reflecting the best practices of the industry would be helpful.
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. With respect to Requirement R1.2 - How about simply ‘Summer and winter peak actual and weather corrected peak if observed, forecast load (one year ahead).’ This requires provision of the weather corrected actual which is directly comparable to the forecast. What is meant by “biasing of each load forecast”?4. With respect to Requirement R2.0 - Remove the wording in the parentheses. Each entity has to look at its forecast error. 5. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, the effectiveness of these changes cannot be assessed. These changes should be delayed until the complete impacts of MOD-016 and these proposals can be assessed. 6. R2 adds an immeasurable requirement that could be clarified by requiring an entity to annually check its load forecast, and acceptable variances. When these variances are exceeded the entity would take defined actions to improve the load forecast.
David A. Lapinski	Consumers Energy	3	Disapprove	As written, R1.2 and R2 apply to peak Load. They should apply Interruptible Demands and Direct Control Load Management, the subject of this standard. As is, they essentially duplicate the requirements of R1.5 and R2 of draft MOD-017. In R1.5 the term "peak Forecast variation" is not clear. Is this intended to be the difference between forecast and actual demand? R2 (and therefore the VSL) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	As written, R1.2 and R2 apply to peak Load. They should apply Interruptible Demands and Direct Control Load Management, the subject of this standard. As is, they essentially duplicate the requirements of R1.5 and R2 of draft MOD-017. In R1.5 the term "peak Forecast variation" is not clear. Is this intended to be the difference between forecast and actual demand? R2 (and therefore the VSL) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes

Voter	Entity	Segment	P 1277	Comments
				would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
Terry L Baker	Platte River Power Authority	3	Approve	Clarity is needed for this requirement. Is annual review needed for hourly, monthly, seasonal or annual peaks?
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	Do not agree with the concept of developing an indices that indicates the “accuracy, error and bias” between forecasted loads and actual loads as indicated by proposed additions of requirements R1.2 and R2. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to “normalize” actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different “latent heat” or “latent cold” build-ups. Poor indications of load accuracy are of no value and can be misleading.In addition, techniques developed by load forecasting groups to “compare” actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.It is inappropriate to include Regional Entities as an entity to provide forecasted load data. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain forecasted load information as defined in this Standard MOD-019. See definition below:Regional Entity - The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	FE defers to and supports its RTO organizations (PJM and MISO) regarding the proposed load forecasting changes.

Voter	Entity	Segment	P 1277	Comments
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	
Timothy VanBlaricom	California ISO	2	Disapprove	For California ISO, interruptible demand and direct control load is a required program under the jurisdiction of the California PUC. It's a subscription for those who want to participate in the program. The CPUC counts the interruptible demand and direct control load as a resource and, as such, is not forecasted in the manner that load is. System need determines whether this resource is called upon and in most years only portions of the programs are call on, so there is no "actual" amount to do an error analysis against, nor to do an error analysis of the program.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	How is this to be accomplished? Industry still has questions on how to adequately do this without introducing additional error. This is not a simple request/task.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	In R2 the words "e.g. ..if" should be removed or replaced by "when". It should be made clear when the assuptions need to be reviewed.
Lee Schuster	Florida Power Corporation	3	Disapprove	In R2, is the parenthetical statement "(e.g., if variation expressed in terms of error divided by actual demand is greater than 10%)" a requirement or just a suggestion? It should probably be deleted to avoid confusion.
James Eckelkamp	Progress Energy	6	Disapprove	
Wayne Lewis	Progress Energy Carolinas	5	Disapprove	
Jason Shaver	ATC	1	Disapprove	Load (1-year, 5-year, and 10-year) forecast accuracy can not be reviewed (checked) until 1 year, 5 year, and 10 years later. The accuracy of the different future timeframes are not the same. The 10-year forecast will be much less accurate than the 1-year forecast. The assumptions that can cause large variances in the load forecast (weather, macro economics, micro economic, technology, etc.) may vary widely over 1 year, 5 year , and 10 year timeframes.
Harold Taylor, II	GTC	1	Disapprove	Mod-019 R2. This requirement is a virtual copy of Mod-017 R2 and as written does not address FERC's directive. We believe the intended distinction between the two is that MOD-019 R2 should be focused on interruptible load. If so, it should be rewritten to reflect that. Our comment on MOD-017R2 regarding the need for a clear statement of conditions when action is required instead of giving an example of when action is required is also applicable here.
Guy Andrews	Georgia System	4	Disapprove	MOD-019 R2. This requirement is a virtual copy of MOD-017 R2 and as written does not address

Voter	Entity	Segment	P 1277	Comments
	Operations Corporation			FERC's directive. We believe the intended distinction between the two is that MOD-019 R2 should be focused on interruptible load. If so, it should be rewritten to reflect that. Our comment on MOD-017R2 regarding the need for a clear statement of conditions when action is required instead of giving an example of when action is required is also applicable here.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Greg C Parent	Manitoba Hydro	3	Disapprove	o Paragraph 1277: The intent of Requirement R2 is not clear. The load variation threshold is not clear. Is the threshold of 10% simply an example of what load forecast variation could be to trigger forecast improvement, or is it meant to implicitly state that load forecast modification must be made if variation is greater than 10%?
Paul Rocha	CenterPoint Energy	1	Disapprove	Paragraph 1277 directs the ERO to add a new requirement that would apply to resource planners. The proposed R2 goes beyond the directive as it applies to LSE, PA, and TP as well as resource planners therefore CenterPoint Energy disapproves of this change.
Michael F Gildea	Dominion Resources Services	3	Disapprove	Paragraphs 1276 - 1277 - While we agree that the changes address the cited FERC directives, we believe that the proposed changes are significant and therefore warrant significant stakeholder vetting. 1. R1.5 - The language needs to be more specific as to which 'version' of the load forecast is to be compared to actual. Most entities forecast load for any given day at multiple intervals. As example DVP forecasts load for the future 7 days when weather forecast is updated (typically 0400, 1100, and 1600). Weather forecasts are also updated whenever the vendor determines a significant change from previous forecast occurs. This also triggers our load forecast software to produce an updated load forecast. During the actual day, the current day load forecast is updated each hour (for the remaining hours of the day) based upon preliminary 'actual load' for the preceding hour as well as any changes to the weather forecast for the current day.2. R2, as written, could decrease reliability by allowing a wider bandwidth before action is currently utilized by some entities. Also, R2, as written, is un-measurable. We suggest that R2 should be given to a standards drafting team to develop appropriately.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
John K Loftis	Dominion Virginia Power	1	Disapprove	
Doug Bantam	LES	1	Disapprove	Please provide a basis for the 10% threshold since FERC did not state this in Order 693. Not sure how modifying load forecast assumptions to improve accuracy will benefit the BES unless the applicable entity applies it to the upcoming forecast. Please clarify.
Dennis Florom	LES	5	Disapprove	
Eric Ruskamp	LES	6	Disapprove	
Joseph G.	Madison Gas and	4	Disapprove	

Voter	Entity	Segment	P 1277	Comments
DePoorter	Electric Co.			
Jeff Nelson	Springfield Utility Board	3	Disapprove	Please refer to SUB's comment form
Raj Rana	AEP	3	Disapprove	R1.2. The standard title is "Forecasts of Interruptible Demands and DCLM Data" yet R1.2 reference peak forecast variation. Clarification is needed on what is peak (LSE, interruptible loads, etc). Secondly, "biasing of each forecast" is not appropriate phrasing. Loads are forecast to be as accurate as possible without bias. A series of actual loads compared to forecast may show a bias, but forecast are not developed with bias
Edward P. Cox	AEP Marketing	6	Disapprove	
Brock Ondayko	AEP Service Corp.	5	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	R2 - what is the basis for 10%?
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	R2 = actually implement DCLM and compare that to a similair hour whre DCLM in not implemented to calculate the actual ammount and extrapolate the value to peak load..
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Disapprove	R2. The language used for this requirement is unclear. PG&E recommends the following language be used to meet the intent of the Federal Energy Regulatory Commission Order 693:"The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall annually review its interruptible demands and DCLM forecast variation and, if necessary (e.g., if variation expressed in terms of difference between the forecast and actual amount of interruptible demands and DCLM divided by the forecasted amount of interruptible demands and DCLM for the previous year is greater than 10%, after accounting for differences in forecast conditions versus operating conditions when the interruptible demands and DCLM were operated), modify the interruptible demands and DLCM forecast assumptions to improve accuracy. [Violation Risk Factor: Low] [Time Horizon: Operations Assessment]."This language is significantly more precise, addressing the Federal Energy Regulatory Commission's concerns regarding forecasting accuracy of controllable load.
Mel Jensen	APS	5	Disapprove	Requirement R2 should be revised to state "... shall annually review the controllable load forecast ...". Order 693 direction is for controllable forecast, not Load forecast.
Robert D Smith	Arizona Public Service Co.	1	Disapprove	
George T. Ballew	Tennessee Valley Authority	5	Disapprove	Requirements 1.2 and 2 are not in scope for this standard.
Larry Akens	Tennessee Valley Authority	1	Disapprove	Requirements 1.2 and 2 are not in scope for this standard. Additional requirements do not enhance reliability.

Voter	Entity	Segment	P 1277	Comments
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	We suggest that R1.2 and R2 are not in scope for this standard. While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	Short term forecasts can vary from actuals by more than 10% due to uncontrollable weather and long term forecasts can vary from actuals due to unforeseen economic conditions such as the 2008 / 2009 recessions. A zero DSM period when DSM is not used compared to any value is more than a 10% variation. Further DSM can be a very small portion of an overall forecast. Mandating a correction and applying a high VSL to future forecasts for events beyond an entity's control, i.e when an entity "failed to make improvements to improve accuracy", is wrong and unrealistic and could lead to unjustified penalties. MidAmerican objects to the use of "error" in these revisions because while this is the statistical term it does not describe the true nature of the variation in load forecasting. It could be that variation in explanatory variables would indicate that there is "error" in the forecast if it matched exactly the actuals in that case. MidAmerican recommends that "error" in every case be replaced by "variation" or some other words like "the differences between the forecasts and actuals". Finally to penalize for variations is wrong. The penalties should relate to improper development of forecasts. Failure to consider weather when making forecasts when there are weather related loads is an example.The existing modifications while attempting to meet the letter of the FERC Orders, does not improve reliability and will likely have unintended consequences and may reduce system reliability. Neither FERC nor NERC has shown a technical basis or justification of the benefits to enforcing corrections to a potentially small portion of a forecast. Therefore NERC has considered this FERC directive, and met its obligation to address a FERC Order. Nothing states that NERC or the industry must accept a vague or undefined FERC directive.By rushing policy making, taking utility industry control of VRF / VSLs away, raising VRF / VSLs to high levels, and potentially enforcing massive penalties for any violation, regulators have forced entities to look at each word and consider the worst possible outcome, making standards development more difficult. FERC, NERC, and the industry should return to the collaborate standards making process that emphasizes education over enforcement.
Gregory Campoli	New York Independent System Operator	2	Disapprove	Specific to the proposed changes to address the directive in Paragraph 1277, we question the basis for the 10% error if used as a threshold for R2. Further, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumptions even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that
Tom Bowe	PJM Interconnection,	2	Disapprove	

Voter	Entity	Segment	P 1277	Comments
	L.L.C.			R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2.
Charles H Yeung	Southwest Power Pool	2	Disapprove	Specific to the proposed changes to address the directive in Paragraph 1277, we question the basis for the 10% error if used as a threshold for R2. Further, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumptions even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. Since these MOD standards are predicated upon MOD-016-1 and it has yet to be approved by FERC, we cannot assess the effectiveness of these changes. These changes should be delayed until we can assess the complete impacts of MOD-016 and these proposals.
Daniel Prowse	Manitoba Hydro	6	Disapprove	The intent of Requirement R2 is not clear. The load variation threshold is not clear. Is the threshold of 10% simply an example of what load forecast variation could be to trigger forecast improvement, or is it meant to implicitly state that load forecast modification must be made if variation is greater than 10%?
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Disapprove	The original inclination was to approve these changes in support of NERC's objectives to expedite attention to certain Order 693 Directives; however, from interaction with colleagues in the industry there appears to be sufficient concern/confusion about how an entity would comply with the proposed revisions that additional vetting is appropriate.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	The proposed requirement R2, which includes review of Load forecastaccuracy, goes beyond the FERC directive, which includes review of onlycontrollable Load forecast accuracy. Even with that clarification, believe thatindustry will still consider this controversial. We would further question thejustification of 10% forecast error. The forecast error that would be used in thisstandard needs to have a technical basis and it is doubtful in this expedited SARany technical analysis was conducted to determine the appropriate value.Certainly no technical analysis was provided with the posting. We suspect thatthis number proposed could actually reduce reliability.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen	Southern Co. Services, Inc.	1	Disapprove	

Voter	Entity	Segment	P 1277	Comments
Williamson				
Randall McCamish	City of Vero Beach	1	Disapprove	This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.
Walt Gill	Lake Worth Utilities	1	Disapprove	
Larry E Watt	Lakeland Electric	1	Disapprove	
Donald Gilbert	JEA	5	Approve	This is acceptable if it is understood that forecasting interruptible and DCLM load is highly dependent on individual customer's business cycles/activities and could vary significantly during economic downturns as recently experienced.
Danny McDaniel	Cleco Power LLC	1	Disapprove	This will require an entity to review its Load forecast accuracy and adjust to within 10%. What is the basis for the 10% variation?
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	Too prescriptive. See comments above.R2 is not measurable.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	United illuminating agrees with the intent but has concerns with the requirement R2. The statement in parenthesis is unclear if NERC is establishing 10% as the allowable variation or not. It's inappropriate to use e.g in a VSL matrix.UI suggests that the entity developing the Load Forecast maintains a document describing the allowable variation and how it is calculated.The Standard requires two Load Forecasts a two year monthly (R1.3) and as requested a five to ten year forecast (R1.4). It is unclear which forecast is being addressed in R2.
Terry L.	Santee Cooper	1	Disapprove	We consider these changes to be significant and believe that these type of changes need to go

Voter	Entity	Segment	P 1277	Comments
Blackwell				through the Reliability Standards development process.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We do not believe that the directives in paragraph 1276 and 1277 represent low hanging fruit that can be accomplished by this ad hoc and expedited SAR. We believe the Commission likely would have the same view given their use of "innovative solutions" in their directive in paragraph 1276. Innovation takes time. Clearly, a group of experts needs to be convened in a drafting team to address this Commission directive. We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce reliability.
Kim Warren	IESO	2	Disapprove	We question the basis for the 10% error if used as a threshold for R2. Further, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumptions even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2. Further, the 10% threshold seems loose. Is it in effect saying that the responsible entity should review it forecasting process on an annual basis? Sometimes an error of 10% is totally explainable and should not warrant a change in forecast methodology (this is especially true for long term forecasts where weather is uncertain). It is prudent to review the methodology but to change it for changes sake is not. And does the load forecast mean Load forecast peak MW demand, peak hour energy demand, minimum demand, or all of the above?In addition, R2 is added without a corresponding M2. And why is Forecast (not a defined term) capitalized in R1.2 but not so elsewhere? Should interruptible demands be interruptible Loads?
George R. Bartlett	Entergy Corporation	1	Disapprove	While we agree that the changes address the cited FERC directives, we do not believe that additional requirements improve or enhance reliability.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	
Saurabh Saksena	National Grid	1	Disapprove	With respect to Requirement R2.0 - Remove the wording in the parentheses. Also, delete it from the VSL.
John C. Collins	Platte River Power Authority	1	Approve	Yes, but add comment that clarity is needed for this requirement. Is annual review needed for hourly, monthly, seasonal or annual peaks?

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Francis J. Halpin	Bonneville Power Administration	5	In Favor	
Rebecca Berdahl	Bonneville Power Administration	3	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Paul Morland	Colorado Springs Utilities	1	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
Daniel Herring	Detroit Edison Co.	4	In Favor	

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Walter Yeager	Duke Energy Carolina	6	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Thomas E Washburn	FMPP	6	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Donald Gilbert	JEA	5	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Steven Grego	MEAG Power	3	In Favor	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	In Favor	
John Bos	Muscatine Power & Water	3	In Favor	

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
John C. Collins	Platte River Power Authority	1	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	
Tim Hattaway	PowerSouth Energy Cooperative	5	In Favor	
Laurie Williams	Public Service Co. of New Mexico	1	In Favor	
Philip Riley	Public Service Commission of	9	In Favor	

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
	South Carolina			
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
John T. Underhill	Salt River Project	3	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Dennis Sismaet	Seattle City Light	6	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Bethany Wright	SMUD	5	In Favor	
James Leigh-Kendall	SMUD	3	In Favor	
Mike Ramirez	SMUD	4	In Favor	
Tim Kelley	SMUD	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
Richard McLeon	South Texas Electric Cooperative	1	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	
John Tolo	Tucson Electric Power Co.	1	In Favor	
Brandy A Dunn	Western Area Power Administration	1	In Favor	
Louise McCarren	Western Electricity Coordinating Council	10	In Favor	
Terry L Baker	Platte River Power Authority	3	In Favor	Clarity is needed for this requirement. Is annual review needed for hourly, monthly, seasonal or annual peaks?
Guy Andrews	Georgia System Operations Corporation	4	In Favor	Refer to comments above.
Raj Rana	AEP	3	Opposed	

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Edward P. Cox	AEP Marketing	6	Opposed	
Brock Ondayko	AEP Service Corp.	5	Opposed	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky Power Coop.	3	Opposed	
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
George R. Bartlett	Entergy Corporation	1	Opposed	
Stanley M Jaskot	Entergy Corporation	5	Opposed	
Robert Martinko	FirstEnergy Energy Delivery	1	Opposed	
Kenneth Dresner	FirstEnergy Solutions	5	Opposed	

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Kevin Querry	FirstEnergy Solutions	3	Opposed	
Mark S Travaglianti	FirstEnergy Solutions	6	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
David T. Anderson	Ocala Electric Utility	3	Opposed	

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Douglas Hohlbaugh	Ohio Edison Co.	4	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Bruce Glorvigen	OTP Wholesale Marketing	6	Opposed	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Opposed	
Mark A. Heimbach	PPL Generation LLC	5	Opposed	
James Eckelkamp	Progress Energy	6	Opposed	
Wayne Lewis	Progress Energy Carolinas	5	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	
Terry L. Blackwell	Santee Cooper	1	Opposed	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H Yeung	Southwest Power Pool	2	Opposed	
RJames Rocha	Tampa Electric Co.	5	Opposed	
Ronald L Donahey	Tampa Electric Co.	3	Opposed	
George T. Ballew	Tennessee Valley Authority	5	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Jonathan Appelbaum	United Illuminating Co.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
David A. Lapinski	Consumers Energy	3	Opposed	As written, R1.2 and R2 apply to peak Load. They should apply Interruptible Demands and Direct Control Load Management, the subject of this standard. As is, they essentially duplicate the requirements of R1.5 and R2 of draft MOD-017. In R1.5 the term "peak Forecast variation" is not clear. Is this intended to be the difference between forecast and actual demand? R2 (and therefore the VSL) is highly subjective. This requires load forecast assumptions to be modified to improve accuracy "if necessary". Compliance review for this proposed standard would involve a professional assessment and judgement by the auditor that modification was necessary and that the changes would improve accuracy. The parenthetical represents a judgement or tacit suggestion by the drafting team that should be deleted.
David Frank Ronk	Consumers Energy	4	Opposed	
James B Lewis	Consumers Energy	5	Opposed	
Jason L	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 1277 in their current format, we

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Marshall				cannot support the changes to the VSLs.
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Terri Pyle	Oklahoma Municipal Power Authority	4	Opposed	How is this to be accomplished? Industry still has questions on how to adequately do this without introducing additional error. This is not a simple request/task.
Brad Jones	Luminant Energy	6	Opposed	No opinion
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.
Bob Essex	Cowlitz County PUD	5	Opposed	Pinning down when an entity has “failed to make improvements to improve accuracy when such improvements were necessary (e.g., variation was greater than 10%)” may be a very difficult audit task. Consider a hypothetical case where an entity has modified Load forecast assumptions each year over a 6-year period in an effort to improve accuracy. However, two consecutive year’s variation is much greater than 10%; has the entity “failed to make improvements” as “necessary?” Should a violation be assessed? Cowlitz PUD suggests the following verbiage: The responsible entity reviewed its Load forecast accuracy on an annual basis, but failed to make any effort to improve accuracy.
Russell A Noble	Cowlitz County PUD	3	Opposed	
Rick Syring	Cowlitz County PUD	4	Opposed	
Jeff Nelson	Springfield Utility Board	3	Opposed	Please refer to SUB's comment form
Gregg R Griffin	City of Green Cove Springs	3	Opposed	R2 = actually implement DCLM and compare that to a similair hour whre DCLM in not implemented to calculate the actual ammount and extrapolate the value to peak load..
Kim Warren	IESO	2	Opposed	R2 needs to be changed first.
Charles Locke	Kansas City Power & Light Co.	3	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
Michael Gammon	Kansas City Power & Light Co.	1	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Opposed	Refer to comments above.

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Harold Taylor, II	GTC	1	Opposed	
Saurabh Saksena	National Grid	1	Opposed	See comments above.
Randall McCamish	City of Vero Beach	1	Opposed	See comments to "Changes for directive in Paragraph 1277"
Frank Gaffney	Florida Municipal Power Agency	4	Opposed	
Walt Gill	Lake Worth Utilities	1	Opposed	
Larry E Watt	Lakeland Electric	1	Opposed	
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	Specific to the proposed changes to address the directive in Paragraph 1277, we question the basis for the 10% error if used as a threshold for R2. Further, in the requirement, the 10% is cited as an example, which means the responsible entity does not need to modify load forecast assumptions even at an error greater than 10%. Standards cannot be written with loose language if the intent is to mandate responsible entities to take action to address potential unreliability. We again suggest that R2 be pulled off from this round of revision. It follows that we do not agree with the changes to the VSLs for R1 and R2.
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Opposed	The High VSL and Severe VSL should be modified to read:High VSL: “The responsible entity reviewed its interruptible demands and DCLM forecast accuracy on an annual basis, but failed to demonstrate that the entity implemented improvements that should improve accuracy over previous forecasts when such improvements were necessary (e.g., variation was greater than 10%).”This language accounts for the fact that not all planned improvements will actually decrease the forecast error and that the responsible entity should not be considered in violation of the standard when the intent was met, but the result was contrary to expectation. This language requires the responsible entity to demonstrate why a planned improvement should increase the forecasting accuracy.Severe VSL: “The responsible entity failed to review its interruptible demands and DCLM forecast accuracy on an annual basis.”This language is more precise than the original language and removes possible ambiguity regarding what data is required.
Donald E.	Commonwealth of	9	Opposed	The inclusion of VRFs and VSL's to versions of standards that do not have them should be fully

Voter	Entity	Segment	P 1277 VRF and VSLs	Comments
Nelson	Massachusetts Department of Public Utilities			vetted by the industry.
Rex A Roehl	Indeck Energy Services, Inc.	5	Opposed	The R2 VSL's should be Lower and Moderate instead of High and Severe. The reliability impact of this inaccuracy is hardly measurable. This seems like double jeopardy with the same VSL criteria as MOD-017.
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P1287:

The Response Team has considered the comments received on these modifications and determined that addressing the directive(s) will require more extensive discussion than can be addressed within this effort. The changes have been removed from consideration during the balloting process.

With the changes now removed from consideration for balloting, comments received will be not be responded to individually at this time. However, they will be retained for future consideration when these directives are addressed again.

Voter	Entity	Segment	P 1287	Comments
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore G&E Co.	1	Abstain	
Timothy VanBlaricom	California ISO	2	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Robert Smith	Duke Energy	5	Abstain	
Dan	Dynegy Inc.	5	Abstain	

Voter	Entity	Segment	P 1287	Comments
Roethemeyer				
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
Robert Mattey	Ohio Valley Electric Corp.	1	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret	Pacific Northwest	8	Abstain	

Voter	Entity	Segment	P 1287	Comments
Ryan	Generating Cooperative			
Ronald Schloendorn	PECO Energy	1	Abstain	
Scott Peterson	San Diego G&E	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Alan Gale	City of Tallahassee	5	Abstain	This will require an actual activation of DCLM. Otherwise it is all "pie-in-the-sky" and who can say that I am right ot wrong in my forecast. Why does the registered entity have to report to NERC and the RE? We should report to the RE only and they should forward to ERO. As written, my compliance relies on performance of the RE, or aI have to submit the same data to both places.
Jason L. Murray	AESO	2	Approve	

Voter	Entity	Segment	P 1287	Comments
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Jason Shaver	American Transmission Co., LLC	1	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	

Voter	Entity	Segment	P 1287	Comments
Paul Morland	Colorado Springs Utilities	1	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	

Voter	Entity	Segment	P 1287	Comments
Kenneth Dresner	FirstEnergy Solutions	5	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Donald Gilbert	JEA	5	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Approve	
Charlie Martin	Louisville Gas and Electric Co.	5	Approve	
Daryn Barker	Louisville Gas and Electric Co.	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Steven Grego	MEAG Power	3	Approve	
Randi	Minnesota Power,	1	Approve	

Voter	Entity	Segment	P 1287	Comments
Woodward	Inc.			
Dan R. Schoenecker	MRO	10	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
John Apperson	PacifiCorp	3	Approve	

Voter	Entity	Segment	P 1287	Comments
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Tim Hattaway	PowerSouth Energy Cooperative	5	Approve	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Approve	
Mark A. Heimbach	PPL Generation LLC	5	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
Jeffrey Mueller	PSE&G	3	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	

Voter	Entity	Segment	P 1287	Comments
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Bethany Wright	Sacramento Municipal Utility District	5	Approve	
James Leigh-Kendall	Sacramento Municipal Utility District	3	Approve	
Mike Ramirez	Sacramento Municipal Utility District	4	Approve	
Tim Kelley	Sacramento Municipal Utility	1	Approve	

Voter	Entity	Segment	P 1287	Comments
	District			
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
Guy Andrews	Georgia System	4	Approve	Recommend re-writing R2 to not have sub-requirements since there is only one (1) sub-requirement.

Voter	Entity	Segment	P 1287	Comments
	Operations Corporation			
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	Recommend re-writing R2 to not have sub-requirements since there is only one (1) sub-requirement.
Harold Taylor, II	GTC	1	Approve	Recommend re-writing R2 to not have sub-requirements since there is only one (1) sub-requirement.
Kenneth D. Brown	PSE&G	1	Approve	While the PSEG companies are voting to approve, PSEG believes that the the modifier "controllable" before DSM is redundant and can be deleted in all sections since DSM implies dispatchability. Non-controllable load modification generally falls into the category of energy efficiency (or energy conservation) measures.
Edward P. Cox	AEP Marketing	6	Disapprove	
Brock Ondayko	AEP Service Corp.	5	Disapprove	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Disapprove	
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen	East Kentucky	5	Disapprove	

Voter	Entity	Segment	P 1287	Comments
Ricker	Power Coop.			
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Disapprove	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Disapprove	
Saurabh Saksena	National Grid	1	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
David T. Anderson	Ocala Electric Utility	3	Disapprove	
Daniel Baerman	San Diego G&E	5	Disapprove	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power	5	Disapprove	

Voter	Entity	Segment	P 1287	Comments
	Association			
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Disapprove	
RJames Rocha	Tampa Electric Co.	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. General comment - In the "NERC Comments" section, remove the "Section B" descriptor of the Requirements. 2. General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry. 3. With respect to Requirement R2.1 - How is this different from MOD-019 R1.1? This seems like a duplication of what is in MOD-019 and perhaps, they should be combined.
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	Do not agree with the concept of developing an indices that indicates the "accuracy, error and bias" between forecasted loads and actual loads as indicated by proposed additions of requirements R2 and R2.1. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to "normalize" actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different "latent heat" or "latent cold" build-ups. Poor indications of load accuracy are of no value and can be misleading. In addition, techniques developed by load forecasting groups to "compare" actual data to forecasted data will be subjective

Voter	Entity	Segment	P 1287	Comments
				and will present difficulty in disproving or proving load forecasting accuracies in an audit. It is inappropriate to include Regional Entities as an entity to provide forecasted load data. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain forecasted load information as defined in this Standard MOD-020. See definition below: Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	Do not agree with the concept of developing an indices that indicates the "accuracy, error and bias" between forecasted loads and actual loads as indicated by proposed additions of requirements R2 and R2.1. A fair comparison of load forecast occurs when forecasted temperatures and humidity match actual temperatures and humidity. When there is not a match of temperature and humidity, the loads will be understandably different and any attempts to "normalize" actual load to forecasted load based on temperature and humidity differences introduces assumption and error of its own. The difficulty of this comparison is further compounded by the differences imposed by off-peak temperature differences resulting in different "latent heat" or "latent cold" build-ups. Poor indications of load accuracy are of no value and can be misleading.In addition, techniques developed by load forecasting groups to "compare" actual data to forecasted data will be subjective and will present difficulty in disproving or proving load forecasting accuracies in an audit.It is inappropriate to include Regional Entities as an entity to provide forecasted load data. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain forecasted load information as defined in this Standard MOD-020. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.

Voter	Entity	Segment	P 1287	Comments
Laurie Williams	Public Service Co. of New Mexico	1	Disapprove	Exact information about the amount of available controllable load will be difficult to determine and unlikely to be very accurate, therefore not adding any significant benefit to system reliability and planning.
Terry Harbour	MidAmerican Energy Co.	1	Disapprove	Forecasts can be vary from actuals by more than 10% due to uncontrollable weather and long term forecasts can be off due to unforeseen economic conditions such as the 2008 / 2009 recessions. A zero DSM period when DSM is not used compared to any value is more than a 10% variation. Further DSM can be a very small portion of an overall forecast. Therefore mandating forecasting “error” (MidAmerican believes this term should be called variation or differences between forecasts and actuals) improvements and bias report will not improve system reliability, cannot provide entities with advanced knowledge about the exact amount of available controllable load as too many variables exist, and will not measurably improve the accuracy of system reliability assessments.In fact, MidAmerican objects to the use of error in these revisions because while this is the statistical term it does not describe the true nature of the variation in DSM forecasting. It could be that variation in explanatory variables would indicate that there is “error” in the forecast if it matched exactly the actuals in that case. MidAmerican recommends that “error” in every case be replaced by “variation” or some other words like “the differences between the forecasts and actuals”. Finally to penalize for variations is wrong. The penalties should relate to improper development of forecasts. For example, failure to consider weather when making forecasts of DSM when there is weather related DSM.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	General comment - In the “NERC Comments” section, remove the “Section B” descriptor of the Requirements. With respect to Requirement R2.1 - How is this different from MOD-019 R1.1? This seems like a duplication of what is in MOD-019 and perhaps, they should be rolled together.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	How is this to be accomplished? Industry still has questions on how to adequately do this without introducing additional error. This is not a simple request/task.
Charles H Yeung	Southwest Power Pool	2	Disapprove	In the context of the entire requirement, the proposed change does not address the definition and implication of DCLM. Such issues are in many cases state regulator related. The proposed R2.1 computation/metric is a newly created requirement that is not required by the directive and should be processed through the Reliability Standards Development Process before it is approved.
Greg C Parent	Manitoba Hydro	3	Disapprove	o See comments regarding R1.2's "biasing" and R2's "modify load forecast assumptions" given in MOD-017

Voter	Entity	Segment	P 1287	Comments
Michael F Gildea	Dominion Resources Services	3	Disapprove	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load. It should also be noted than if this requirement is approved, it may lead to the need for additional metering, which has been opposed by demand response as a ‘barrier to entry’. FERC has shown opposition to efforts at RTO/ISO forums that have proposed additional metering for demand response.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load. It should also be noted than if this requirement is approved, it may lead to the need for additional metering, which has been opposed by demand response as a ‘barrier to entry’. FERC has shown opposition to efforts at RTO/ISO forums that have proposed additional metering for demand response.
Mike Garton	Dominion Resources, Inc.	5	Disapprove	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load. It should also be noted than if this requirement is approved, it may lead to the need for additional metering, which has been opposed by demand response as a ‘barrier to entry’. FERC has shown opposition to efforts at RTO/ISO forums that have proposed additional metering for demand response.
John K Loftis	Dominion Virginia Power	1	Disapprove	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load. It should also be noted than if this requirement is approved, it may lead to the need for additional metering, which has been opposed by demand response as a ‘barrier to entry’. FERC has shown opposition to efforts at RTO/ISO forums that have proposed additional metering for demand response.

Voter	Entity	Segment	P 1287	Comments
George R. Bartlett	Entergy Corporation	1	Disapprove	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	Paragraph 1287 - R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.
Jeff Nelson	Springfield Utility Board	3	Disapprove	Please refer to SUB's comment form
Kirit S. Shah	Ameren Services	1	Disapprove	R1 and R2.1 - Add ",DSM," after interruptible demands
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	R2 = actually implement DCLM and compare that to a similair hour whre DCLM in not implemented to calculate the actual ammount and extrapolate the value to peak load..
Raj Rana	American Electric Power	3	Disapprove	R2.1 "...biasing of each forecast" is not appropriate phasing. Loads are forecast to be as accurate as possible without bias. A series of actual loads compared to forecast may show a bias, but forecast are not developed with bias.
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Disapprove	R2.1. The language used for this requirement is unclear. PG&E recommends the following language be used to meet the intent of the Federal Energy Regulatory Commission Order 693:"Summer and winter peak forecast variation of interruptible demands and DCLM for the previous year, expressed in terms of the difference between the forecast and actual amount of interruptible demands and DCLM divided by the forecasted amount of interruptible demands and DCLM for the previous year, accounting for differences in forecast versus operating conditions when the interruptible demands and DCLM were operated, as well as any biasing of each forecast of interruptible demands and DCLM."This language is significantly more precise in the actual information to be supplied and explicitly accounts for differences between planning forecasts and operational results that are caused by differences in environmental and other operational conditions that could not be accounted for during a planning forecast.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	Regarding R2, how does one calculate the actual interruptible demand or DCLM after the fact unless that demand is interrupted? Is that coincident with the peak demand? It will simply be a guess and not useful data.

Voter	Entity	Segment	P 1287	Comments
Nickesha P Carrol	ConEd of NY	6	Disapprove	Requirement R2 should incorporate the words "on request" in order to be consistent with Requirement 1.
Christopher L de Graffenried	ConEd of NY	1	Disapprove	Requirement R2 should incorporate the words “on request” in order to be consistent with Requirement R1.
Wilket (Jack) Ng	ConEd of NY	5	Disapprove	Requirement R2 should incorporate the words “on request” in order to be consistent with Requirement R1.
Peter T Yost	ConEd of NY	3	Disapprove	Requirement R2 should incorporate the words “on request” in order to be consistent with Requirement R1.
Daniel Prowse	Manitoba Hydro	6	Disapprove	See comments regarding R1.2's "biasing" and R2's "modify load forecast assumptions" given in MOD-017
Michelle Rheault	Manitoba Hydro	1	Disapprove	See comments regarding R1.2's "biasing" and R2's "modify load forecast assumptions" given in MOD-017
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	Seems to duplicate MOD-019 R1.1
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Gregory Campoli	New York Independent System Operator	2	Disapprove	Taken in isolation the proposed change to R1 is appropriate. All the identified entities must respond to data requests of reliability entities that require the data. In the context of the entire requirement, the proposed change does not address the definition and implication of DCLM. Such issues are in many cases state regulator related. FERC is correct that this is a complex issue and the idea that simply mandating forecast data ignores the fact of that complexity. The requirement lacks clarity in definition of what DCLM is; what biases the standard is seeking and who needs what information for reliability. The ERO has recognized the complexity associated with this area by initiating a Demand Resource Team. This change should take into account the findings of those initiatives. The proposed R2.1 computation/metric is a newly created requirement that is not required by the directive and should be processed through the Reliability Standards Development Process before it is approved.
Tom Bowe	PJM Interconnection,	2	Disapprove	Taken in isolation the proposed change to R1 is appropriate. All the identified entities must respond to data requests of reliability entities that require the data. In the context of the entire

Voter	Entity	Segment	P 1287	Comments
	L.L.C.			requirement, the proposed change does not address the definition and implication of DCLM. Such issues are in many cases state regulator related. FERC is correct that this is a complex issue and the idea that simply mandating forecast data ignores the fact of that complexity. The requirement lacks clarity in definition of what DCLM is; what biases the standard is seeking and who needs what information for reliability. The ERO has recognized the complexity associated with this area by initiating a Demand Resource Team. This change should take into account the findings of those initiatives. The proposed R2.1 computation/metric is a newly created requirement that is not required by the directive and should be processed through the Reliability Standards Development Process before it is approved.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	The exact amount of interruptible load and demand side management reponse in a given instant may not be known after the fact.
Larry Akens	Tennessee Valley Authority	1	Disapprove	The exact amount of interruptible load and demand side management response in a given instant may not be known after the fact. Interruptible load and demand side response is typically not metered separately from the base load.
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	R2 - The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data – interruptible load and demand side response is typically not metered separate from the base load
Richard J. Mandes	Alabama Power Co.	3	Disapprove	The exact amount of interruptible load and demand side response in a giveninstant may be unknowable after the fact unless it is exercised in that moment.It is inappropriate to have a mandatory national standard that requires thereporting of intrinsically unknowable data - interruptible load and demand sideresponse is typically not metered separate from the base load.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	The exact amount of interruptible load and demand side response in a giveninstant may be unknowable after the fact unless it is exercised in that moment.It is inappropriate to have a mandatory national standard that requires thereporting of intrinsically unknowable data - interruptible load and demand sideresponse is typically not metered separate from the base load.
Gwen S Frazier	Gulf Power Co.	3	Disapprove	The exact amount of interruptible load and demand side response in a giveninstant may be unknowable after the fact unless it is exercised in that moment.It is inappropriate to have a mandatory national standard that requires thereporting of intrinsically unknowable data - interruptible load and demand sideresponse is typically not metered separate from the base load.
Don Horsley	Mississippi Power	3	Disapprove	The exact amount of interruptible load and demand side response in a giveninstant may be

Voter	Entity	Segment	P 1287	Comments
				unknowable after the fact unless it is exercised in that moment.It is inappropriate to have a mandatory national standard that requires thereporting of intrinsically unknowable data - interruptible load and demand sideresponse is typically not metered separate from the base load.
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	The exact amount of interruptible load and demand side response in a given instant may be unknowable after the fact unless it is exercised in that moment. It is inappropriate to have a mandatory national standard that requires the reporting of intrinsically unknowable data - interruptible load and demand side response is typically not metered separate from the base load.
Bob C. Thomas	Illinois Municipal Electric Agency	4	Disapprove	The original inclination was to approve these changes in support of NERC's objectives to expedite attention to certain Order 693 Directives; however, from interaction with colleagues in the industry there appears to be sufficient concern/confusion about how an entity would comply with the proposed revisions that additional vetting is appropriate.
Ronald L Donahey	Tampa Electric Co.	3	Disapprove	The scope of the exercise does not justify the benefits of the increased accuracy.
Randall McCamish	City of Vero Beach	1	Disapprove	This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.
Walt Gill	Lake Worth Utilities	1	Disapprove	This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task
Larry E Watt	Lakeland Electric	1	Disapprove	This directive is not low hanging fruit to be addressed in this fashion. The only way we can think of to accomplish the proposed R2 is to actually implement DCLM and compare that to a similar hour where DCLM is not implemented to calculate the actual amount of DCLM, and then somehow extrapolate

Voter	Entity	Segment	P 1287	Comments
				the value to what would be available at peak load (which is still a calculation introducing forecast error). This is not a simple task.
Danny McDaniel	Cleco Power LLC	1	Disapprove	This is a duplication of a requirement in MOD-019-1.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	This is a duplication of a requirement in MOD-019-1.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	This seems like a duplication of what is in MOD-019 R1.1 and perhaps, they should be rolled together.
Terry L. Blackwell	Santee Cooper	1	Disapprove	We consider these changes to be significant and believe that these type of changes need to go through the Reliability Standards development process.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We do not believe that the directives in paragraph 1287 represent low hanging fruit that can be accomplished by this ad hoc and expedited SAR. A group of experts needs to be convened in a drafting team to address this Commission directive. We would further question the justification of 10% forecast error. The forecast error that would be used in this standard needs to have a technical basis and it is doubtful in this expedited SAR any technical analysis was conducted to determine the appropriate value. Certainly no technical analysis was provided with the posting. We suspect that this number proposed could actually reduce reliability. Adding sub-requirement R2.1 and modifying sub-requirements R1.1 and R1.2 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be.
Kim Warren	IESO	2	Disapprove	We do not understand the meaning of "biasing". Is it operator adjustments? If so, isn't forecaster/operator expertise part of the forecasting process? Forecasting (especially long term) is not just a mechanical exercise but requires "value-added" actions by the forecaster. Biasing is not a defined term.
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	Wording is confusing and parts are repetitive with MOD-19-1

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
Rodney Phillips	Allegheny Power	1	In Favor	
Bob Reeping	Allegheny Power	3	In Favor	
Kevin Koloini	American Municipal Power - Ohio	4	In Favor	
Mel Jensen	APS	5	In Favor	
Robert D Smith	Arizona Public Service Co.	1	In Favor	
James V. Petrella	Atlantic City Electric Co.	3	In Favor	
Eric Egge	Black Hills Corp	1	In Favor	
Francis J. Halpin	Bonneville Power Administration	5	In Favor	
Rebecca Berdahl	Bonneville Power Administration	3	In Favor	
John Yale	Chelan County Public Utility District #1	5	In Favor	
Linda R. Jacobson	City of Farmington	3	In Favor	
Paul Morland	Colorado Springs Utilities	1	In Favor	
Carolyn Ingersoll	Constellation Energy	3	In Favor	
David A. Lapinski	Consumers Energy	3	In Favor	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
David Frank Ronk	Consumers Energy	4	In Favor	
James B Lewis	Consumers Energy	5	In Favor	
Bob Essex	Cowlitz County PUD	5	In Favor	
Russell A Noble	Cowlitz County PUD	3	In Favor	
Rick Syring	Cowlitz County PUD	4	In Favor	
Daniel Herring	Detroit Edison Co.	4	In Favor	
Michael F Gildea	Dominion Resources Services	3	In Favor	
Louis S Slade	Dominion Resources, Inc.	6	In Favor	
Mike Garton	Dominion Resources, Inc.	5	In Favor	
John K Loftis	Dominion Virginia Power	1	In Favor	
Walter Yeager	Duke Energy Carolina	6	In Favor	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	In Favor	
Robert Martinko	FirstEnergy Energy Delivery	1	In Favor	
Kenneth Dresner	FirstEnergy Solutions	5	In Favor	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
Kevin Querry	FirstEnergy Solutions	3	In Favor	
Mark S Travaglianti	FirstEnergy Solutions	6	In Favor	
Lee Schuster	Florida Power Corporation	3	In Favor	
Kenneth Simmons	Gainesville Regional Utilities	3	In Favor	
Guy Andrews	Georgia System Operations Corporation	4	In Favor	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	In Favor	
Harold Taylor, II	GTC	1	In Favor	
Mace Hunter	Lakeland Electric	3	In Favor	
Doug Bantam	LES	1	In Favor	
Dennis Florom	LES	5	In Favor	
Eric Ruskamp	LES	6	In Favor	
Steven Grego	MEAG Power	3	In Favor	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	In Favor	
John Bos	Muscatine Power & Water	3	In Favor	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
David H. Boguslawski	Northeast Utilities	1	In Favor	
John Canavan	NorthWestern Energy	1	In Favor	
Douglas Hohlbaugh	Ohio Edison Co.	4	In Favor	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	In Favor	
Michael T. Quinn	Oncor Electric Delivery	1	In Favor	
Jerome Murray	Oregon Public Utility Commission	9	In Favor	
Bruce Glorvigen	OTP Wholesale Marketing	6	In Favor	
John Apperson	PacifiCorp	3	In Favor	
Mark Sampson	PacifiCorp	1	In Favor	
Sandra L. Shaffer	PacifiCorp	5	In Favor	
Terry L Baker	Platte River Power Authority	3	In Favor	
John C. Collins	Platte River Power Authority	1	In Favor	
Frank F. Afranji	Portland General Electric Co.	1	In Favor	
Richard J Kafka	Potomac Electric Power Co.	1	In Favor	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
Tim Hattaway	PowerSouth Energy Cooperative	5	In Favor	
Brenda L Truhe	PPL Electric Utilities Corp.	1	In Favor	
Mark A. Heimbach	PPL Generation LLC	5	In Favor	
James Eckelkamp	Progress Energy	6	In Favor	
Wayne Lewis	Progress Energy Carolinas	5	In Favor	
Philip Riley	Public Service Commission of South Carolina	9	In Favor	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	In Favor	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	In Favor	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	In Favor	
Greg Lange	Public Utility District No. 2 of Grant County	3	In Favor	
Thomas J. Bradish	RRI Energy	5	In Favor	
Trent Carlson	RRI Energy	6	In Favor	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
Bethany Wright	Sacramento Municipal Utility District	5	In Favor	
James Leigh-Kendall	Sacramento Municipal Utility District	3	In Favor	
Mike Ramirez	Sacramento Municipal Utility District	4	In Favor	
Tim Kelley	Sacramento Municipal Utility District	1	In Favor	
Glen Reeves	Salt River Project	5	In Favor	
John T. Underhill	Salt River Project	3	In Favor	
Robert Kondziolka	Salt River Project	1	In Favor	
Dana Wheelock	Seattle City Light	3	In Favor	
Dennis Sismaet	Seattle City Light	6	In Favor	
Hao Li	Seattle City Light	4	In Favor	
Pawel Krupa	Seattle City Light	1	In Favor	
Richard Jones	South Carolina Electric & Gas Co.	5	In Favor	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	In Favor	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
John Tolo	Tucson Electric Power Co.	1	In Favor	
Jonathan Appelbaum	United Illuminating Co.	1	In Favor	
Brandy A Dunn	Western Area Power Administration	1	In Favor	
Louise McCarren	Western Electricity Coordinating Council	10	In Favor	
Edward P. Cox	AEP Marketing	6	Opposed	
Brock Ondayko	AEP Service Corp.	5	Opposed	
Richard J. Mandes	Alabama Power Co.	3	Opposed	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Opposed	
Raj Rana	American Electric Power	3	Opposed	
Paul Rocha	CenterPoint Energy	1	Opposed	
Brian Conroy	Central Maine Power Co.	1	Opposed	
Robert W. Roddy	Dairyland Power Coop.	1	Opposed	
George S. Carruba	East Kentucky Power Coop.	1	Opposed	
Sally Witt	East Kentucky	3	Opposed	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
	Power Coop.			
Stephen Ricker	East Kentucky Power Coop.	5	Opposed	
George R. Bartlett	Entergy Corporation	1	Opposed	
Stanley M Jaskot	Entergy Corporation	5	Opposed	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Opposed	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Opposed	
Anthony L Wilson	Georgia Power Co.	3	Opposed	
Gwen S Frazier	Gulf Power Co.	3	Opposed	
Jim D. Cyrulewski	JDRJC Associates	8	Opposed	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Opposed	
Charlie Martin	Louisville Gas and Electric Co.	5	Opposed	
Daryn Barker	Louisville Gas and Electric Co.	6	Opposed	
Terry Harbour	MidAmerican Energy Co.	1	Opposed	
Don Horsley	Mississippi Power	3	Opposed	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
Saurabh Saksena	National Grid	1	Opposed	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Opposed	
David T. Anderson	Ocala Electric Utility	3	Opposed	
Robert Mattey	Ohio Valley Electric Corp.	1	Opposed	
Laurie Williams	Public Service Co. of New Mexico	1	Opposed	
Daniel Baerman	San Diego G&E	5	Opposed	
Terry L. Blackwell	Santee Cooper	1	Opposed	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Opposed	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Opposed	
Steve McElhaney	South Mississippi Electric Power Association	4	Opposed	
Jerry W Johnson	South Mississippi Electric Power Association	5	Opposed	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Opposed	
Charles H	Southwest Power	2	Opposed	

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
Yeung	Pool			
RJames Rocha	Tampa Electric Co.	5	Opposed	
Ronald L Donahey	Tampa Electric Co.	3	Opposed	
George T. Ballew	Tennessee Valley Authority	5	Opposed	
Barry Ingold	Tri-State G & T Association Inc.	5	Opposed	
Keith V. Carman	Tri-State G & T Association Inc.	1	Opposed	
Liam Noailles	Xcel Energy, Inc.	5	Opposed	
Ajay Garg	Hydro One Networks, Inc.	1	Opposed	Addition of VRFs and VSLs to portions of standards thast did not havwe them in the first place is inappropriate.
Michael D. Penstone	Hydro One Networks, Inc.	3	Opposed	
Jason L Marshall	Midwest ISO, Inc.	2	Opposed	Because we do not support the proposed changes for paragraph 1287 in their current format, we cannot support the changes to the VSLs.
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Opposed	General comment - The inclusion of VRFs and Time Horizons to versions of standards that do not have them should be fully vetted by the industry.
Kathleen Goodman	ISO New England, Inc.	2	Opposed	Generally, if we do not support the change, we do not agree with the VSL.
Terri Pyle	Oklahoma Municipal Power Authority	4	Opposed	How is this to be accomplished? Industry still has questions on how to adequately do this without introducing additional error. This is not a simple request/task.
Brad Jones	Luminant Energy	6	Opposed	No opinion

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
Mike Laney	Luminant Generation Co. LLC	5	Opposed	Opposed as we were not provided with the option to abstain on this particular vote.
Jeff Nelson	Springfield Utility Board	3	Opposed	Please refer to SUB's comment form
Gregg R Griffin	City of Green Cove Springs	3	Opposed	R2 = actually implement DCLM and compare that to a similair hour whre DCLM in not implemented to calculate the actual ammount and extrapolate the value to peak load..
Kim Warren	IESO	2	Opposed	R2 needs to be changed first.
Charles Locke	Kansas City Power & Light Co.	3	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
Michael Gammon	Kansas City Power & Light Co.	1	Opposed	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.
Randall McCamish	City of Vero Beach	1	Opposed	See comments to "Changes for directive in Paragraph 1287"
Frank Gaffney	Florida Municipal Power Agency	4	Opposed	
Walt Gill	Lake Worth Utilities	1	Opposed	
Larry E Watt	Lakeland Electric	1	Opposed	
Richard McLeon	South Texas Electric Cooperative	1	Opposed	Severity should be based on impact to system reliability. The "one size" (Severe) fits all isn't logical.
Tom Bowe	PJM Interconnection, L.L.C.	2	Opposed	Taken in isolation the proposed change to R1 is appropriate. All the identified entities must respond to data requests of reliability entities that require the data. In the context of the entire requirement, the proposed change does not address the definition and implication of DCLM. Such issues are in many cases state regulator related. FERC is correct that this is a complex issue and the idea that simply mandating forecast data ignores the fact of that complexity. The requirement lacks clarity in definition of what DCLM is; what biases the standard is seeking and who needs what information for reliability. The ERO has recognized the complexity associated with this area by initiating a Demand Resource Team. This change should take into account the findings

Voter	Entity	Segment	P 1287 VRF and VSLs	Comments
				of those initiatives. The proposed R2.1 computation/metric is a newly created requirement that is not required by the directive and should be processed through the Reliability Standards Development Process before it is approved.
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Opposed	the Severe VSL should be modified to read:Severe VSL: "The responsible entity failed to annually provide interruptible demand and Direct Control Load Management(DCLM) forecast variation, expressed in terms of the difference between the forecast and actual amount of interruptible demands and DCLM divided by the forecasted amount of interruptible demands and DCLM for the previous year, accounting for differences in forecast versus operating conditions when the interruptible demands and DCLM were operated, for forecasts performed within the previous year."This language is more precise than the original language and removes possible ambiguity regarding what data is required.
Rex A Roehl	Indeck Energy Services, Inc.	5	Opposed	The VSL level should be Lower. The reliability significance of DSM variation is minimal even where large DSM programs are in place.
Donald Gilbert	JEA	5	Opposed	This should not be a high severity under the definitions of severity levels. Maybe there needs to be an allowance gradient applied across the levels and only great disregard for compliance based on significant delays and multiple notifications should be high.
James A Ziebarth	Y-W Electric Association, Inc.	4	Opposed	Y-WEA abstains from this question.

Summary Consideration for changes related to P1300:

Two entities expressed confusion regarding the provision of documentation and measurement of DSM performance. The response team was uncertain what changes, if any, were being proposed or objected to. This comment appeared to be directed at requirements in the currently approved standard.

Two other entities suggested that the word “Controllable” should not be deleted, as it indicates non-controllable DSM is acceptable. However the team and the majority of commenters believe that the word “Controllable” is redundant in this case, and can be removed.

Voter	Entity	Segment	P 1300	Comments
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore Gas & Electric Co.	1	Abstain	
Timothy VanBlaricom	California ISO	2	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Abstain	
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	

Voter	Entity	Segment	P 1300	Comments
Robert Smith	Duke Energy	5	Abstain	
Dan Roethemeyer	Dynegy Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
Robert Mattey	Ohio Valley Electric Corp.	1	Abstain	
Mark Ringhausen	Old Dominion Electric Coop.	4	Abstain	

Voter	Entity	Segment	P 1300	Comments
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Daniel Baerman	San Diego Gas & Electric	5	Abstain	
Scott Peterson	San Diego Gas & Electric	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Edward P.	AEP Marketing	6	Approve	

Voter	Entity	Segment	P 1300	Comments
Cox				
Brock Ondayko	AEP Service Corp.	5	Approve	
Richard J. Mandes	Alabama Power Co.	3	Approve	
Jason L. Murray	Alberta Electric System Operator	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Kirit S. Shah	Ameren Services	1	Approve	
Mark Peters	Ameren Services	3	Approve	
Sam Dwyer	Amerenue	5	Approve	
Raj Rana	American Electric Power	3	Approve	
Kevin Koloini	American Municipal Power - Ohio	4	Approve	
Jason Shaver	American Transmission Co., LLC	1	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V.	Atlantic City	3	Approve	

Voter	Entity	Segment	P 1300	Comments
Petrella	Electric Co.			
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
Paul Rocha	CenterPoint Energy	1	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Nickesha P Carrol	ConEd of NY	6	Approve	
Christopher L de Graffenried	ConEd of NY	1	Approve	

Voter	Entity	Segment	P 1300	Comments
Wilket (Jack) Ng	ConEd of NY	5	Approve	
Peter T Yost	ConEd of NY	3	Approve	
Carolyn Ingersoll	Constellation Energy	3	Approve	
David A. Lapinski	Consumers Energy	3	Approve	
David Frank Ronk	Consumers Energy	4	Approve	
James B Lewis	Consumers Energy	5	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Robert W. Roddy	Dairyland Power Coop.	1	Approve	
Daniel Herring	Detroit Edison Co.	4	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	

Voter	Entity	Segment	P 1300	Comments
John K Loftis	Dominion Virginia Power	1	Approve	
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
George S. Carruba	East Kentucky Power Coop.	1	Approve	
Sally Witt	East Kentucky Power Coop.	3	Approve	
Stephen Ricker	East Kentucky Power Coop.	5	Approve	
George R. Bartlett	Entergy Corporation	1	Approve	
Stanley M Jaskot	Entergy Corporation	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	
Kenneth Dresner	FirstEnergy Solutions	5	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	

Voter	Entity	Segment	P 1300	Comments
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Anthony L Wilson	Georgia Power Co.	3	Approve	
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Harold Taylor, II	GTC	1	Approve	
Gwen S Frazier	Gulf Power Co.	3	Approve	
Ajay Garg	Hydro One Networks, Inc.	1	Approve	
Michael D. Penstone	Hydro One Networks, Inc.	3	Approve	
Bob C.	Illinois Municipal	4	Approve	

Voter	Entity	Segment	P 1300	Comments
Thomas	Electric Agency			
Kim Warren	Independent Electricity System Operator	2	Approve	
Kathleen Goodman	ISO New England, Inc.	2	Approve	
Jim D. Cyrulewski	JDRJC Associates	8	Approve	
Donald Gilbert	JEA	5	Approve	
Charles Locke	Kansas City Power & Light Co.	3	Approve	
Michael Gammon	Kansas City Power & Light Co.	1	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Approve	
Charlie Martin	Louisville Gas and Electric Co.	5	Approve	
Daryn Barker	Louisville Gas and	6	Approve	

Voter	Entity	Segment	P 1300	Comments
	Electric Co.			
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Dan R. Schoenecker	Midwest Reliability Organization	10	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Don Horsley	Mississippi Power	3	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
Saurabh Saksena	National Grid	1	Approve	

Voter	Entity	Segment	P 1300	Comments
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Approve	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L.	Pacific Gas and	1	Approve	

Voter	Entity	Segment	P 1300	Comments
Thomas	Electric Co.			
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Tom Bowe	PJM Interconnection, L.L.C.	2	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Tim Hattaway	PowerSouth Energy Cooperative	5	Approve	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Approve	
Mark A. Heimbach	PPL Generation LLC	5	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	

Voter	Entity	Segment	P 1300	Comments
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Kenneth D. Brown	Public Service Electric and Gas Co.	1	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Bethany Wright	Sacramento Municipal Utility District	5	Approve	
James Leigh-Kendall	Sacramento Municipal Utility District	3	Approve	
Mike Ramirez	Sacramento Municipal Utility District	4	Approve	

Voter	Entity	Segment	P 1300	Comments
Tim Kelley	Sacramento Municipal Utility District	1	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Approve	
Charles H Yeung	Southwest Power Pool	2	Approve	
James L. Jones	Southwest Transmission	1	Approve	

Voter	Entity	Segment	P 1300	Comments
	Cooperative, Inc.			
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
George T. Ballew	Tennessee Valley Authority	5	Approve	
Larry Akens	Tennessee Valley Authority	1	Approve	
Marjorie Parsons	Tennessee Valley Authority	6	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
David F. Lemmons	Xcel Energy, Inc.	6	Approve	
Gregory L Pieper	Xcel Energy, Inc.	1	Approve	
Liam Noailles	Xcel Energy, Inc.	5	Approve	

Voter	Entity	Segment	P 1300	Comments
David Murray	PSEG Power LLC	5	Approve	Comments: While the PSEG companies are voting to approve, PSEG believes that the the modifier "controllable" before DSM is redundant and can be deleted in all sections since DSM implies dispatchability. Non-controllable load modification generally falls into the category of energy efficiency (or energy conservation) measures. Response: Thank you for your supportive comment.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	seems reasonable Response: Thank you for your supportive comment.
Jason L Marshall	Midwest ISO, Inc.	2	Approve	We agree this represents low hanging fruit that could be modified through this expedited SAR. We do note though that the Compliance section of the standard has been modified which exceeds the scope of the SAR. Response: Thank you for your supportive comment. The compliance elements, which are not considered part of the standard, have been updated to reflect the current practices in use today. They do not conflict with the requirements, do not impose any new requirements, and should provide more clarity to entities wishing to comply with the standard. As such, the Response Team believes the updates are both appropriate and within scope.
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Approve	While the PSEG companies are voting to approve, PSEG believes that the the modifier "controllable" before DSM is redundant and can be deleted in all sections since DSM implies dispatchability. Non-controllable load modification generally falls into the category of energy efficiency (or energy conservation) measures. Response: Thank you for your supportive comment.
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	While the PSEG Companies are voting to approve, PSEG Companies believe that the modifier "controllable" before DSM is redundant and can be deleted in all sections since DSM implies dispatchability. Non-controllable load modification generally falls into the category of energy efficiency (or energy conservation) measures. Response: Thank you for your supportive comment.
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Laurie Williams	Public Service Co. of New Mexico	1	Disapprove	

Voter	Entity	Segment	P 1300	Comments
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Gregory Campoli	New York Independent System Operator	2	Disapprove	General comment - If the Transmission Planner gets its information from the LSE, must it duplicate the documentation? The impact of many DSM programs is not measurable. Response: The comments provided do not relate to any specific changes proposed as a part this project. To the extent the industry wishes to make additional changes to improve the standard, we encourage such efforts.
David H. Boguslawski	Northeast Utilities	1	Disapprove	General comment - If the Transmission Planner gets its information from the LSE, must it duplicate the documentation? The impact of many DSM programs is not measurable. Response: The comments provided do not relate to any specific changes proposed as a part this project. To the extent the industry wishes to make additional changes to improve the standard, we encourage such efforts.
Danny McDaniel	Cleco Power LLC	1	Disapprove	We should leave the controllable language in the standard. We need to maintain control of the DSM in order to effectively incorporate it into the demand and energy forecast. Response: The Response Team believes the word "Controllable" is redundant. Specific attributes of DSM will need to be addressed through further work.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Disapprove	Wording is changed from a very specific type Demand Side Management, to a very vague definition or a catch all. Wording needs to clearly specify the DSM this MOD is addressing. Response: The Response Team believes the word "Controllable" is redundant. Specific attributes of

Voter	Entity	Segment	P 1300	Comments
				DSM will need to be addressed through further work.

Summary Consideration for changes related to P1469:

Several entities expressed concern with the inclusion of the Load Serving Entity and the Transmission Operator, as well as the language related to "joint" ownership. The Response Team removed these changes from the standard and, with the exception of modifications related to the Regional Entity and RRO, generally returned the requirements to their original state.

Several entities pointed out that R3 and M3 still contained references to the Regional Reliability Organization (RRO). The Response Team modified R3 and M3 to correct this error.

Some entities suggested that Regional Reliability Organization was the correct term to use in this context. The Response Team believes Regional Entity is correct, and notes that the RE is not being assigned requirements in the standard, making the distinction somewhat less important.

Voter	Entity	Segment	P 1469	Comments
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore Gas & Electric Co.	1	Abstain	
Timothy VanBlaricom	California ISO	2	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Thomas E Washburn	FMPP	6	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Rex A Roehl	Indeck Energy	5	Abstain	

Voter	Entity	Segment	P 1469	Comments
	Services, Inc.			
Brad Jones	Luminant Energy	6	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Abstain	
Douglas G Peterchuck	Omaha Public Power District	1	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Tim Hattaway	PowerSouth Energy Cooperative	5	Abstain	
Mark A. Heimbach	PPL Generation LLC	5	Abstain	
Laurie Williams	Public Service Co. of New Mexico	1	Abstain	
Daniel Baerman	San Diego Gas & Electric	5	Abstain	
Scott Peterson	San Diego Gas & Electric	3	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Scott M. Helyer	Tenaska, Inc.	5	Abstain	
Kathleen	ISO New England,	2	Abstain	Since LSEs and TOPs do not own physical assets, they should not be included. ISO - NE, whom

Voter	Entity	Segment	P 1469	Comments
Goodman	Inc.			originally submitted the comment which resulted in the Directive, agrees and believes that the directive is no longer applicableR3 should be reworded to reflect RE just like the other requirements have been modified Response: The Response Team has removed the Load Serving Entity and Transmission Operator, as suggested. R3 has been updated to use the correct "Regional Entity" phrasing.
Jason L. Murray	Alberta Electric System Operator	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Jason Shaver	American Transmission Co., LLC	1	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Nickesha P	ConEd of NY	6	Approve	

Voter	Entity	Segment	P 1469	Comments
Carrol				
Christopher L de Graffenried	ConEd of NY	1	Approve	
Wilket (Jack) Ng	ConEd of NY	5	Approve	
Peter T Yost	ConEd of NY	3	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
Robert Smith	Duke Energy	5	Approve	
Douglas E. Hils	Duke Energy Carolina	1	Approve	
Henry Ernst-Jr	Duke Energy Carolina	3	Approve	
Walter Yeager	Duke Energy Carolina	6	Approve	
Dan Roethemeyer	Dynegy Inc.	5	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Lee Schuster	Florida Power	3	Approve	

Voter	Entity	Segment	P 1469	Comments
	Corporation			
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Greg Froehling	Green Country Energy	5	Approve	
Donald Gilbert	JEA	5	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
John W Delucca	Lee County Electric Cooperative	1	Approve	
Daniel Duff	Liberty Electric Power LLC	5	Approve	
Mike Laney	Luminant Generation Co. LLC	5	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Randi Woodward	Minnesota Power, Inc.	1	Approve	

Voter	Entity	Segment	P 1469	Comments
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
Saurabh Saksena	National Grid	1	Approve	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Approve	
James	Progress Energy	6	Approve	

Voter	Entity	Segment	P 1469	Comments
Eckelkamp				
Wayne Lewis	Progress Energy Carolinas	5	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Approve	
Kenneth D. Brown	Public Service Electric and Gas Co.	1	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Bethany Wright	Sacramento Municipal Utility District	5	Approve	
James Leigh-Kendall	Sacramento Municipal Utility District	3	Approve	

Voter	Entity	Segment	P 1469	Comments
Mike Ramirez	Sacramento Municipal Utility District	4	Approve	
Tim Kelley	Sacramento Municipal Utility District	1	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Terry L. Blackwell	Santee Cooper	1	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Jeff Nelson	Springfield Utility Board	3	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Martin Bauer	U.S. Bureau of	5	Approve	

Voter	Entity	Segment	P 1469	Comments
P.E.	Reclamation			
Brandy A Dunn	Western Area Power Administration	1	Approve	
Liam Noailles	Xcel Energy, Inc.	5	Approve	
James B Lewis	Consumers Energy	5	Approve	Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot "own" facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE's suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM. Response: The Response Team has removed the Load Serving Entity and Transmission Operator from the standard. However, we do not believe it is appropriate to remove those entities from the Glossary and the Functional Model.
Kevin Koloini	American Municipal Power - Ohio	4	Approve	Please consider removing LSE from the applicability to reduce unnecessary "not applicable" filings. Response: The Response Team has removed the Load Serving Entity from the standard as suggested.
Bob Essex	Cowlitz County PUD	5	Approve	Requirement R3 still contains an old reference to the "Regional Reliability Organization" which now should read "Regional Entity." Also, Cowlitz PUD struggles in understanding how the LSE should be applicable. By definition from the Glossary, the DP is the functional entity that "provides and operates the 'wires' between the transmission system and the end-use customer," and therefore is the owner of any transmission Protective System. The LSE by definition only "secures energy and transmission service" and apparently does not own or operate the distribution facilities. Any LSE that owns distribution facilities by definition must also register as a DP. Further, the Reliability Functional Model clearly states that the LSE "coordinates with Distribution Provider on indentifying new facility interconnection needs," which implies the DP must provide and own the System Protection improvements. Cowlitz PUD advises NERC to clarify this apparent misunderstanding of the FERC, and upon Commission approval, remove the LSE from Section 4, Applicability. For the time being, the inclusion is harmless. Response: The Response Team has corrected the reference to "RRO" as suggested. Additionally, the
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	

Voter	Entity	Segment	P 1469	Comments
				team has removed the Load Serving Entity as suggested.
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	see WECC comments Response: Please see WECC response.
Bob C. Thomas	Illinois Municipal Electric Agency	4	Approve	The addition of LSE does not make sense given the current Reliability Functional Model definition. Response: The Response Team has removed the Load Serving Entity as suggested.
Eric Egge	Black Hills Corp	1	Approve	The addition of LSE's and TO's was to be considered, but not necessarily accepted. The changes are acceptable but leave a little confusion about which misoperations each entity is required to address. Suggested revised wording for R1: The Transmission Owner and any entity listed below that individually or jointly owns a transmission Protection System shall analyze Misoperations of the transmission Protection Systems that it owns and shall develop and implement a Corrective Action Plan for those Misoperations according to the Regional Entity's procedures to avoid future Misoperations similar in nature. Additionally, PRC-003-0 is a Fill-in-the-blank standard. As NERC revises the Fill-in-the-blank standards to remove the Regional Reliability Organization as an applicable entity, the language of PRC-004-2 (as well as many others) will need to be revised to remove the phase "according to the Regional Entity's procedures. Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters. We agree that as revisions to the standards occur, they will need to be coordinated to ensure no gaps are created as entities change.
Brenda S. Anderson	Bonneville Power Administration	6	Approve	The addition of LSE's and TO's was to be considered, but not necessarily accepted. The changes are acceptable but leave a little confusion about which misoperations each entity is required to address. See our proposed modification: Suggested wording for R1: The Transmission Owner and any entity listed below that individually or jointly owns a transmission Protection System shall analyze Misoperations of the transmission Protection Systems that it owns and shall develop and implement a Corrective Action Plan for those Misoperations according to the Regional Entity's procedures to avoid future Misoperations of a similar nature. Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.
Donald S. Watkins	Bonneville Power Administration	1	Approve	The addition of LSE's and TO's was to be considered, but not necessarily accepted. The changes are acceptable but leave a little confusion about which misoperations each entity is required to address. See our proposed modification: Suggested wording for R1: The Transmission Owner and any entity
Francis J.	Bonneville Power	5	Approve	

Voter	Entity	Segment	P 1469	Comments
Halpin	Administration			listed below that individually or jointly owns a transmission Protection System shall analyze Misoperations of the transmission Protection Systems that it owns and shall develop and implement a Corrective Action Plan for those Misoperations according to the Regional Entity's procedures to avoid future Misoperations of a similar nature. Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	The addition of LSE's and TO's was to be considered, but not necessarily accepted. The changes are acceptable but leave a little confusion about which misoperations each entity is required to address. Suggested revised wording for R1: The Transmission Owner and any entity listed below that individually or jointly owns a transmission Protection System shall analyze Misoperations of the transmission Protection Systems that it owns and shall develop and implement a Corrective Action Plan for those Misoperations according to the Regional Entity's procedures to avoid future Misoperations similar in nature. Additionally, PRC-003-0 is a Fill-in-the-blank standard. As NERC revises the Fill-in-the-blank standards to remove the Regional Reliability Organization as an applicable entity, the language of PRC-004-2 (as well as many others) will need to be revised to remove the phase "according to the Regional Entity's procedures." Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters. We agree that as revisions to the standards occur, they will need to be coordinated to ensure no gaps are created as entities change.
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Dana Wheelock	Seattle City Light	3	Approve	The addition of LSE's and TO's was to be considered, but not necessarily accepted. The changes are acceptable but leave a little confusion about which misoperations each entity is required to address. See our proposed modification: Suggested wording for R1: The Transmission Owner and any entity listed below that individually or jointly owns a transmission Protection System shall analyze Misoperations of the transmission Protection Systems that it owns and shall develop and implement a Corrective Action Plan for those Misoperations according to the Regional Entity's procedures to avoid future Misoperations of a similar nature. Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	The addition of LSE's and TO's was to be considered, but not necessarily accepted. The changes are acceptable but leave some confusion about which misoperations each entity is required to address. Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.

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Louise McCarren	Western Electricity Coordinating Council	10	Approve	The addition of LSE’s and TO’s was to be considered, but not necessarily accepted. The changes are acceptable but leave a little confusion about which misoperations each entity is required to address. Suggested revised wording for R1: The Transmission Owner and any entity listed below that individually or jointly owns a transmission Protection System shall analyze Misoperations of the transmission Protection Systems that it owns and shall develop and implement a Corrective Action Plan for those Misoperations according to the Regional Entity’s procedures to avoid future Misoperations similar in nature. Additionally, PRC-003-0 is a Fill-in-the-blank standard. As NERC revises the Fill-in-the-blank standards to remove the Regional Reliability Organization as an applicable entity, the language of PRC-004-2 (as well as many others) will need to be revised to remove the phase “according to the Regional Entity’s procedures.” Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters. We agree that as revisions to the standards occur, they will need to be coordinated to ensure no gaps are created as entities change.
Randall McCamish	City of Vero Beach	1	Approve	The directive is to "consider ISO-NE’s suggestion that LSEs and transmission operators should be included in the applicability section". In this case, while we do not oppose the change, we do not know of any cases where an LSE or TOP has a transmission Protection System, so, we do not know why LSEs and TOPs are being added to the applicability. Can someone identify a transmission Protection System owned by an LSE or TOP that is not already covered by a TO, GO or DP? Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	The Transmission Owner and any entity listed below that individually or jointly owns a transmission Protection System shall analyze Misoperations of the transmission Protection Systems that it owns and shall develop and implement a Corrective Action Plan for those Misoperations according to the Regional Entity’s procedures to avoid future Misoperations of a similar nature. Response: The Response Team appreciates this suggestion; however, we have removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters, and will instead leave the requirement in its previous form.
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	We have suggested language for R1: "The transmission owner and any entity listed below that individually or jointly owns a transmission Protection System shall analyze Misoperations of the transmission Protection System that it owns and shall develop and implement a Corrective Action Plan for those Misoperations according to the Regional Entity's procedures to avoid future

Voter	Entity	Segment	P 1469	Comments
				Misoperations of a similar nature." Response: The Response Team appreciates this suggestion; however, we have removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters, and will instead leave the requirement in its previous form.
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Carolyn Ingersoll	Constellation Energy	3	Disapprove	
Brenda Powell	Constellation Energy Commodities Group	6	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Kevin Querry	FirstEnergy Solutions	3	Disapprove	

Voter	Entity	Segment	P 1469	Comments
Mark S Travaglianti	FirstEnergy Solutions	6	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Dan R. Schoenecker	Midwest Reliability Organization	10	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Bruce Glorvigen	OTP Wholesale Marketing	6	Disapprove	
Bradley Tollerson	OTP Wholesale Marketing	3	Disapprove	
Lawrence R. Larson	Otter Tail Power Co.	1	Disapprove	
Stacie Hebert	Otter Tail Power Co.	5	Disapprove	
John Apperson	PacifiCorp	3	Disapprove	
Mark Sampson	PacifiCorp	1	Disapprove	
Sandra L. Shaffer	PacifiCorp	5	Disapprove	

Voter	Entity	Segment	P 1469	Comments
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Richard McLeon	South Texas Electric Cooperative	1	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(a) The Glossary of Terms still uses RRO, why the change to Regional Entity? (b) The industry has finally approved Project 2009-17 which clarifies the transmission Protection System border. But 2009-17 refers to PRC-004-1. Please expand 2009-17 so that it is applicable to this proposed PRC-004-2, or better yet incorporate the 2009-17 wording into PRC-004-2. (c) We do not believe that LSE and TOP would own Protection Systems. The standard should not apply to LSE and TOP. Response: NERC is in the process of replacing all references to RRO with RE, due to discussions regarding the delegation of responsibility and the role of the regional entity within the standard development process. It is our belief that 2009-17 will retain the ability to work on this modified standard, as the subject matter of the SAR will not have changed. The Response Team has removed the Load Serving Entity and Transmission Operator as suggested.
Raj Rana	American Electric Power	3	Disapprove	: If these changes are made, this will create applicability to entities that are not involved in other related PRC standards. AEP does not support this “urgent” action as it will create confusion between

Voter	Entity	Segment	P 1469	Comments
				this and other PRC standards going forward. Furthermore, in AEP's experiences, TOP and LSEs are likely not to have involvement in these requirements, but it should be the TO, DP and GO that are involved. The inclusion of the LSE in this standard continues to muddy the water between the role of the LSE and the DP. The NERC Statement of Registry Criteria states that a DP "Provides and operates the 'wires' between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage." In addition, an LSE is defined as an entity that "secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers." This issue has been a considerable problem with how standards were written in the past and NERC has committed to addressing these unfortunate and confusing overlaps in responsibility, but these proposed changes will only perpetuate the problem. We recommend that any entity that has such protection systems should be registered as a TO, DP or GO, The issue then would become one of the ability of the RE to appropriately register entities, not a deficiency in the NERC standards.Again, the other PRC standards are focused on the TO function. This would again cause a mismatch in the applicability with these standards. The first sentence of requirement R1 should be revised to begin "The Transmission Owner, Distribution Provider and the Generator Owner that individually or jointly owns a transmission Protection System, shall each..." AEP Generation owns transmission Protection Systems and believes that the intent of this standard is that all transmission Protection System misoperations are analyzed, regardless of the ownership of the equipment. Furthermore, revising requirement R1 brings the analysis requirements in line with the documentation requirements of R3 which requires a Generator Owner who owns a transmission Protection System to "... provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans...". Also, note that "Regional Reliability Organization" should actually be "Regional Entity". Measure M1 should be revised to include the Generator Owner, as suggested above, and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."Measure M2 should be revised to be consistent with R2 and read "The Generator Owner shall have evidence it analyzed its generator Protection System Misoperations..." and to and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."Measure M3 should be revised to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."The Data Retention section should be revised to remove reference to the "generation Protection System" and should instead read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall retain..."The Additional

Voter	Entity	Segment	P 1469	Comments
				Compliance Information section should be revised to read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall demonstrate..." Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to your comments as well as the suggestions of other commenters.
David H. Boguslawski	Northeast Utilities	1	Disapprove	1. Since LSEs and TOPs do not own physical assets, they should not be included. ISO - NE agrees and believes that the directive is no longer applicable. 2. There is still no clarification on when a DP "owns" a transmission Protection System. Distribution Providers likely own and/or operate equipment matching the definition in the NERC Glossary; however, such does not constitute the owning and/or operation of a "transmission" protection system. In what instances would the NERC Glossary definition of a Protection System apply to a DP?3. R3 should be reworded to reflect RE just like the other requirements have been modified. Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters. This is being addressed though other ongoing projects at NERC. The intent of this project is to only address those items that are non-controversial in nature. R2 has been modified as suggested.
Brian Evans-Mongeon	Utility Services, Inc.	8	Disapprove	As the understanding of LSE has changed since the request was made, it is not appropriate to include LSE in the applicability entities at this time. The other proposed language changes to DPs were not in the directive and should not be incorporated. Response: The Response Team has removed the Load Serving as suggested. The additional changes have been removed as well, save those related to the Regional Entity.
James V. Petrella	Atlantic City Electric Co.	3	Disapprove	Atlantic City Electric Co. believes the SDT has erred in stating that a protection system may be jointly owned. This was not an issue in Order 693. By definition, a TOP would not own a protection system. Order 693 did not require the addition of LSEs or TOPs, only that they be considered. An LSE that "owns" a protection system is also a DP, so LSE applicability is not needed. Response: The Response Team has removed the Load Serving Entity and Transmission Operator, as well as the joint ownership language, as suggested.
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments." Response: Please see responses to Doug Hohlbaugh.

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Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form Response: Please see the appropriate “Consideration of Comments” for response.
Doug Bantam	LES	1	Disapprove	FERC Order 693 does not state that “individually or jointly” entities that own a Protection System shall analyze and develop a Correction Action Plan. This statement does not improve this Standard. Anyone of the applicable entities can be joint owners of a transmission Protection System but one entity will have this requirement to fulfill those actions of this requirement. Recommend deleting “individually or jointly”. Response: The Response Team has removed the “individually or jointly” language as suggested.
Dennis Florom	LES	5	Disapprove	
Eric Ruskamp	LES	6	Disapprove	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Disapprove	
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and therefore should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and therefore should be removed. R3 refers to Regional Reliability Organization and Regional Entity in the same sentence. The same inconsistency exists in the Measures. Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters. We have also corrected the items in R3 and M3 related to the incorrect use of RRO.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	
Edward P. Cox	AEP Marketing	6	Disapprove	If these changes are made, this will create applicability to entities that are not involved in other related PRC standards. AEP does not support this “urgent” action as it will create confusion between this and other PRC standards going forward. Furthermore, in AEP’s experiences, TOP and LSEs are likely not to have involvement in these requirements, but it should be the TO, DP and GO that are involved. The inclusion of the LSE in this standard continues to muddy the water between the role of the LSE and the DP. The NERC Statement of Registry Criteria states that a DP “Provides and operates the ‘wires’ between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.” In addition, an LSE is defined as an entity that “secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.” This issue has been a considerable problem with how standards were written in the past and NERC has committed to addressing these unfortunate and confusing overlaps in responsibility, but these proposed changes will only perpetuate the problem. We recommend that

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				any entity that has such protection systems should be registered as a TO, DP or GO, The issue then would become one of the ability of the RE to appropriately register entities, not a deficiency in the NERC standards.Again, the other PRC standards are focused on the TO function. This would again cause a mismatch in the applicability with these standards. The first sentence of requirement R1 should be revised to begin "The Transmission Owner, Distribution Provider and the Generator Owner that individually or jointly owns a transmission Protection System, shall each..." AEP Generation owns transmission Protection Systems and believes that the intent of this standard is that all transmission Protection System misoperations are analyzed, regardless of the ownership of the equipment.Furthermore, revising requirement R1 brings the analysis requirements in line with the documentation requirements of R3 which requires a Generator Owner who owns a transmission Protection System to "... provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans...". Also, note that “Regional Reliability Organization” should actually be “Regional Entity”. Measure M1 should be revised to include the Generator Owner, as suggested above, and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."Measure M2 should be revised to be consistent with R2 and read "The Generator Owner shall have evidence it analyzed its generator Protection System Misoperations..." and to and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."Measure M3 should be revised to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."The Data Retention section should be revised to remove reference to the "generation Protection System" and should instead read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall retain..."The Additional Compliance Information section should be revised to read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall demonstrate..." Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to your comments as well as the suggestions of other commenters.
Brock Ondayko	AEP Service Corp.	5	Disapprove	If these changes are made, this will create applicability to entities that are not involved in other related PRC standards. AEP does not support this “urgent” action as it will create confusion between this and other PRC standards going forward. Furthermore, in AEP’s experiences, TOP and LSEs are likely not to have involvement in these requirements, but it should be the TO, DP and GO that are involved. The inclusion of the LSE in this standard continues to muddy the water between the role of the LSE and the DP. The NERC Statement of Registry Criteria states that a DP “Provides and operates the ‘wires’ between the transmission system and the end-use customer. For those end-use customers

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				who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage." In addition, an LSE is defined as an entity that "secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers." This issue has been a considerable problem with how standards were written in the past and NERC has committed to addressing these unfortunate and confusing overlaps in responsibility, but these proposed changes will only perpetuate the problem. We recommend that any entity that has such protection systems should be registered as a TO, DP or GO, The issue then would become one of the ability of the RE to appropriately register entities, not a deficiency in the NERC standards.Again, the other PRC standards are focused on the TO function. This would again cause a mismatch in the applicability with these standards. The first sentence of requirement R1 should be revised to begin "The Transmission Owner, Distribution Provider and the Generator Owner that individually or jointly owns a transmission Protection System, shall each..." AEP Generation owns transmission Protection Systems and believes that the intent of this standard is that all transmission Protection System misoperations are analyzed, regardless of the ownership of the equipment. Furthermore, revising requirement R1 brings the analysis requirements in line with the documentation requirements of R3 which requires a Generator Owner who owns a transmission Protection System to "... provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans...". Also, note that "Regional Reliability Organization" should actually be "Regional Entity". Measure M1 should be revised to include the Generator Owner, as suggested above, and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."Measure M2 should be revised to be consistent with R2 and read "The Generator Owner shall have evidence it analyzed its generator Protection System Misoperations..." and to and to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."Measure M3 should be revised to replace the reference to the "Regional Reliability Organization's procedures developed for PRC-003 R1" with the "Regional Entity's procedures."The Data Retention section should be revised to remove reference to the "generation Protection System" and should instead read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall retain..."The Additional Compliance Information section should be revised to read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall demonstrate..." Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to your comments as well as the suggestions of other commenters.

Voter	Entity	Segment	P 1469	Comments
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	It is inappropriate to include Regional Entities as an entity that establishes the criteria and procedures for analysis and reporting of relay mis-operations. The requirements should continue to point to the Regional Reliability Organization or the Reliability Coordinator as the entity that establishes the criteria and procedures for analysis and reporting of relay mis-operations. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to establish the criteria and procedures for analysis and reporting of relay mis-operations as defined in this Standard PRC-004. See definition below: Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified. In addition, it is sufficient to include as an applicable entity the Transmission Owner. It is not necessary, nor is the directive concerned with, the inclusion of the Transmission Operator. The NERC Functional Model clearly indicates the relaying system is the responsibility of the Transmission Owner and not the Transmission Operator. Recommend removal of the Transmission Operator from the Applicability Section and the subsequent references in the requirements. Response: The Response Team has removed the Transmission Operator in response to your comments as well as the suggestions of other commenters. However, we continue to believe that the Regional Entity is appropriate in this context. We note that the Regional Entity has not been assigned any requirements, but simply that entities are expected to comply with the procedures and protocols of those entities.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	It is inappropriate to include Regional Entities as an entity that establishes the criteria and procedures for analysis and reporting of relay mis-operations. The requirements should continue to point to the Regional Reliability Organization or the Reliability Coordinator as the entity that establishes the criteria and procedures for analysis and reporting of relay mis-operations. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to establish the criteria and procedures for analysis and reporting of relay mis-operations as defined in this Standard PRC-004. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority

Voter	Entity	Segment	P 1469	Comments
				through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.In addition, it is sufficient to include as an applicable entity the Transmission Owner. It is not necessary, nor is the directive concerned with, the inclusion of the Transmission Operator. The NERC Functional Model clearly indicates the relaying system is the responsibility of the Transmission Owner and not the Transmission Operator. Recommend removal of the Transmission Operator from the Applicability Section and the subsequent references in the requirements. Response: The Response Team has removed the Transmission Operator in response to your comments as well as the suggestions of other commenters. However, we continue to believe that the Regional Entity is appropriate in this context. We note that the Regional Entity has not been assigned any requirements, but simply that entities are expected to comply with the procedures and protocols of those entities.
Danny McDaniel	Cleco Power LLC	1	Disapprove	It is premature to vote on a standard when the definition for a Protection System is being discussed and could possibly change. See Project 2007-17 Response: In response to stakeholder comments, the Response Team is only making changes related to the Regional Entity. Broader changes are still expected to be addressed in Project 2007-17.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	It remains unclear how an entity can comply with any of the requirements in the absence of a Regional Entity procedure. Response: If a Regional Entity does not have any of the specified procedures, then entities cannot be expected to comply with that particular part of the requirement specifying their use.
David A. Lapinski	Consumers Energy	3	Disapprove	Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot "own" facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE's suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM. Response: The Response Team has removed the Load Serving Entity and Transmission Operator from
David Frank Ronk	Consumers Energy	4	Disapprove	

Voter	Entity	Segment	P 1469	Comments
				the standard. However, we do not believe it is appropriate to remove those entities from the Glossary and the Functional Model.
Charles H Yeung	Southwest Power Pool	2	Disapprove	o The LSE should not be included in requirements R1 and R3 because they are not required to have any assets that would be used for mitigation of generator protection systems misoperations. LSEs arrange secures energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end-use customers. They do not own, or need to own, any transmission, generation or distribution facilities and their associated protection systems. o The changes to R1 are problematic because they introduce a joint applicability (i.e. joint ownership of a Protection System). FERC has required clear applicability - and joint applicability raises the question of how to split responsibility and compliance regarding the mandate to analyze a misoperation, and to develop a mitigation plan. Response: The Response Team has removed the Load Serving Entity from the standard as suggested, as well as the language referring to joint ownership.
George R. Bartlett	Entergy Corporation	1	Disapprove	Paragraph 1469 - Generically, in the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.2 and R1.3 should be included in this standard. Likewise, we do not believe that R3.2 and R3.3 should be included in this standard. Response: The Response Team has removed the Load Serving Entity and Transmission Operator from the standard as suggested.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	Paragraph 1469 clearly states the Commission's expectation that this directive will be addressed through the five-year cycle. Why does this need to be expedited? However, we agree that the changes meet the directive regarding modifying regional reliability organization to Regional Entity. The Commission's directive is to consider adding LSE and TOPs to PRC-004-1 not to actually add them. LSEs and TOPs have no Protection Systems to coordinate. They are not equipment owners per the Functional Model. We agree that the Distribution Provider is a likely candidate for coordination. While the functional model does mention the need for Transmission Owners to develop interconnection agreements with Distribution Providers, it currently is silent on the need to coordinate Protection Systems and appears to give the responsibility for Protection Systems entirely to the Transmission Owner. We suggest that this directive should be referred to the Functional Model Working Group for a proposed resolution and modification of the functional model as necessary. Then a SAR could be developed to address to the Functional Model.Adding sub-requirements R1.1 through R1.3 and R3.1 through R3.3 does not comport with the format that NERC notified the Commission it would use in standards development going forward. NERC submitted the informational

Voter	Entity	Segment	P 1469	Comments
				filing on August 10, 2009, in response, to the Commission's ruling in Order 722. Specifically, the proposal eliminates the use of sub-requirements and proposes to use a numbered or bulleted list based on the characteristics of the list. From the filing: "Rather, NERC will modify such Reliability Standards with the new formatting structure when a project is initiated to review and modify a standard as part of a set of more substantive changes." Submitting sub-requirements is clearly contrary to what NERC notified the Commission its course of action would be. Response: The Response Team has removed the Load Serving Entity and Transmission Operator from the standard, which should eliminate both of the related concerns described. This is being addressed in an expedited fashion, as the Commission seems to have indicated through its words and actions that current progress is not sufficient.
Richard J Kafka	Potomac Electric Power Co.	1	Disapprove	Potomac Electric Power believes the SDT has erred in stating that a protection system may be jointly owned. This was not an issue in Order 693. By definition, A TOP would not own a protection system. Order 693 did not require the addition of LSEs or TOPs, only that they be considered. An LSE that "owns" a protection system is also a DP, so LSE applicability is not needed. Response: The Response Team has removed the language related to joint ownership as suggested.
John Canavan	NorthWestern Energy	1	Disapprove	R1 and R3 have been re-worded such that it seems to require each joint owner of a facility to analyze/report misoperations. NorthWestern believes that the drafting team may have meant to require all jointly-owned units to have relay misoperations analyzed/reported only once. Perhaps the wording should be revised to clarify that each owner is responsible to ensure that this analyzation/eporting occurs for all transmission/generation that the entity has ownership in Response: The Response Team has removed the language related to joint ownership in response to the suggestions of other commenters.
Mark Ringhausen	Old Dominion Electric Coop.	4	Disapprove	R3 has an incorrect title, it uses the RRO title instead of the RE- Regional Entity title. In addition, R3 should be a phrase at the end that the entities must provide the Analsys and Corrective Action Plans upon request by the Regional Entity.Should R1 be changed to require the entity to analyze all Operations? This is the only way I know to determine whether or not an operation is a proper or mis-operation. Response: The Response Team has corrected the title in R3 as suggested, and with the exception of the reference to the Regional Entity, returned the language of R1 to its original state.
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	R3 is reworded so that it applies to a GO that owns a transmission Protection System. It no longer applies to a generator Protection System

Voter	Entity	Segment	P 1469	Comments
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	Response: With the exception of the changes related to the Regional Entity, the Response Team has returned the language of R3 to its original state.
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	See our comments above re. technologies and addition of responsible entities. Response: Please see response above.
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	
Gregory Campoli	New York Independent System Operator	2	Disapprove	Taken in isolation the proposed changes to R1, R2 and R3 are appropriate. In the context of the entire requirement, the proposed change raises the following issues: o The LSE should not be included in requirements R1 and R3 because they are not required to have any assets that would be used for mitigation of generator protection systems misoperations. LSEs arrange energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end-use customers. They do not own, or need to own, any transmission, generation or distribution facilities and their associated protection systems. Further, since both LSEs and TOPs do not own physical assets, they should not be included in the applicability section. ISO-NE, who originally submitted the comment which resulted in the Directive, agrees and believes that the directive is no longer applicable. o The changes to R1 are problematic because they introduce a joint applicability (i.e. joint ownership of a Protection System). FERC has required clear applicability - and joint applicability raises the question of how to split responsibility and compliance regarding the mandate to analyze a misoperation, and to develop a mitigation plan. Response: The Response Team has removed the Load Serving Entity and Transmission Operator as suggested, as well as those related to joint ownership.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	The 693 order states that the ERO should only "consider" the ISO-NE suggestion. It's our view that TOPs don't own protection systems. And the RRO-RE issue does not warrant a revision of the standard at this time. Response: The Response Team has removed the Load Serving Entity and Transmission Operator based on the suggestions of other commenters. The Response Team believes that the RRO-RE issue is appropriate for revision at this time.
James A Ziebarth	Y-W Electric Association, Inc.	4	Disapprove	The proposed changes go significantly beyond the Commission's Order 693 directives and substantially alter the scope of this standard by making all Distribution Providers subject to it. If such

Voter	Entity	Segment	P 1469	Comments
				changes above and beyond FERC's directives are going to be made, then the otherwise undefined term "transmission Protection System" should also be defined clearly enough to avoid such issues as that of Project 2009-17.Beyond this, however, Y-WEA disagrees with the removal of the "that owns a transmission Protection System" qualifier for Distribution Providers in the standard's main Applicability section. By requiring all Distribution Providers to now comply with and keep records for the entire standard even if they own no equipment that has anything to do with this standard, the burden on especially small Distribution Providers will be substantially increased with absolutely no improvement to the reliability of the BES. This proposed change will have significant impact on many entities while making virtually no improvement to BES reliability and is therefore unreasonable and unneeded. Response: The Response Team has removed the Load Serving Entity and Transmission Operator, and restored the deleted language regarding DP applicability.
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Disapprove	The terms "transmission Protection System" and "generator Protection System" are not defined, which makes the requirements of PRC-004-2 unclear. The terms need to be defined locally within the standard, or the requirements need to be re-written. Should the terms be defined locally, than a "transmission protection system" should be defined as "a system with a relay or relays, and all associated protection elements, that provide some degree of primary and/or backup protection for the transmission system." Should the drafting team rewrite the requirements, then Constellation Power Generation proposes combining the requirements into just two requirements as follows:R1. Each Transmission Owner, Generator Owner, Distribution Provider, and Load Serving Entity that owns a Protection System shall each analyze its Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.R2. Each Transmission Owner, Generator Owner, Distribution Provider, and Load Serving Entity that owns a Protection System shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures. Furthermore, the data retention section needs to be re-written in order to match up with the changes in the requirements. Response: The Response Team believes these changes are more extensive than was envisioned for this project. However, we encourage entities to propose such changes as part of a larger effort to improve the standards.
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	In the functional model, the Transmission Operator and Load Serving Entity do not own facilities and should not be included in this standard. We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and therefore should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3

Voter	Entity	Segment	P 1469	Comments
				are applicable to this standard and therefore should be removed. Response: The Response Team has removed the Load Serving Entity and Transmission Operator as suggested.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	The Transmission Operator and the Load Serving Entity do not own facilities and hould not be included in this standard. Requirements 1.1, 1.2,1.3, 3.1, 3.2, and 3.3 are not applicable to this standard. Response: The Response Team has removed the Load Serving Entity and Transmission Operator as suggested.
Larry Akens	Tennessee Valley Authority	1	Disapprove	
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	the transmission owner should be listed in the sub bullet 1.1. R1 should start "Any entity listed below that individually or jointly...". Same comment for R3. Response: The Response Team has removed the Load Serving Entity and Transmission Operator and returned the structure of the requirements to their original state based on concerns expressed by other stakeholders.
Daniel Herring	Detroit Edison Co.	4	Disapprove	There is no need to include LSEs in the applicability section of this standard. Response: The Response Team has removed the Load Serving Entity as suggested.
Kim Warren	Independent Electricity System Operator	2	Disapprove	We agree with the proposed changes to the Applicability Section, Requirements R1, R2 and R3 except the inclusion of the Load-Serving Entity. LSEs arrange secures energy and transmission service (and reliability-related services) to serve the electrical demand and energy requirements of its end-use customers. They do not own, or need to own, any transmission, generation or distribution facilities and their associated protection systems.We suggest to remove LSE from the Applicability Section and the three requirements. Response: The Response Team has removed the Load Serving Entity as suggested.
Robert Martinko	FirstEnergy Energy Delivery	1	Disapprove	We support the change from RRO to RE but must vote no to the 1469 item based on the changes made to R1 and R3 per the 2nd portion of the 1469 directive and ISO-NE's comments in the NOPR.Regarding ISO-NE's suggestion to add LSEs and TOPs as applicable entities to the standard FE disagrees with this change. The LSEs and TOPs are not equipment owners of protection systems and it should be the equipment owners who coordinate this information.In paragraph 1466 ISO-NE raises this as a need "...based on current practice in the ISO-NE balancing area, transmission operators, transmission owners, LSEs and distribution providers may individually or jointly own and operate a protection system. It therefore suggests that transmission operators and LSEs should also be included in the applicability section." If the LSE and TOP is needed in this standard then all of the PRC
Douglas Hohlbaugh	Ohio Edison Co.	4	Disapprove	

Voter	Entity	Segment	P 1469	Comments
				maintenance standards PRC-005, PRC-008, PRC-011 and PRC-017 should also be changed in a like manner. In fact, in paragraph 1466 its stated that ISO-NE recommended this change not only for PRC-004 but also for PRC-005-1, PRC-008-0, PRC-011-0, PRC-015-0, PRC-016-0, PRC-017-0 and PRC-021-1 yet FERC seems to have only directed the ERO to consider ISO-NE's suggestion to change the applicability to include TOPs and LSEs in regard to PRC-004.FE disagrees with the need to add the TOP and LSE as they are not typically an equipment owner of protection systems owned by the TO, DP and GO as the applicability describes. This view is also supported by the NERC Functional Model as well. If ISO-NE has unique needs to include the TOP and LSE entities they should do so through an entity variance. Response: The Response Team has removed the Load Serving Entity and Transmission Operator as suggested.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	With respect to the FERC Order 693 directive in Paragraph 1469, thereference to the Regional Reliability Organization in R3 should be replaced withthe Regional Entity.(replace "... shall each provide to its Regional Reliability Organization..." with"...shall each provide to its Regional Entity...")M1, M2, and M3 need to be changed to match R1, R2, and R3 by:(replacing "... according to the Regional Reliability Organization's proceduresdeveloped for PRC-003 R1." with "... according to the Regional Entity'sprocedures.")Requirement 1 refers to transmission protection systems in the case of TO's,DP's, TOP"S and LSE's while Requirement 2 specifically mentions generatorprotection systems in reference to GO's. In Requirement 3 however it is unclearwhether Generator Owners are held responsible for generator protectionsystems, transmission protection systems or both. Compliance Section - DataRetention - Is the intent that GO's should retain data for an evaluation notprescribed in the Requirements - in the case of a Generator Owner evaluatingtransmission protection systems?Generically, in the functional model, the Transmission Operator and LoadServing Entity do not own facilities and should not be included in this standard.We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard andtherefore should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and therefore should be removed.The Commission's directive is to consider adding LSE and TOPs to PRC-004-1not to actually add them. LSEs and TOPs have no Protection Systems tocoordinate. They are not equipment owners per the Functional Model. We agreethat the Distribution Provider is a likely candidate for coordination. While thefunctional model does mention the need for Transmission Owners to developinterconnection agreements with Distribution Providers, it currently is silent onthe need to coordinate Protection Systems and appears to give the responsibilityfor Protection Systems entirely to the Transmission Owner. We suggest that thisdirective should be referred to the Functional Model Working Group for aproposed resolution and modification of the functional model as necessary. Thena SAR could be
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	

Voter	Entity	Segment	P 1469	Comments
				developed to address to the Functional Model. Response: The Response Team has replaced the RRO with RE in requirement 3 as suggested. Additionally, the team removed the Load Serving Entity and Transmission Operator based on suggestions from other commenters.
William D Shultz	Southern Co. Generation	5	Disapprove	With respect to the FERC Order 693 directive in Paragraph 1469, the reference to the Regional Reliability Organization in R3 should be replaced with the Regional Entity. (I suggest replacing "... shall each provide to its Regional Reliability Organization..." with "...shall each provide to its Regional Entity...")M1, M2, and M3 need to be changed to match R1, R2, and R3. (I suggest replacing "... according to the Regional Reliability Organization's procedures developed for PRC-003 R1." with "... according to the Regional Entity's procedures.")R3, M3, and the Data Retention paragraphs would read a bit easier if the Generator Owner were the first entity listed in each paragraph. (I suggest starting R3 ... "The Generator Owner, the Transmission Owner, and any entity listed below that individually or jointly owns a transmission Protection System shall ...")(I suggest starting M3... "Each Generator Owner, each Transmission Owner, and any Distribution Provider, Transmission Operator, or Load Serving Entity that owns a transmission Protection System shall ...") (I suggest starting Data Retention... "The Generator Owner, the Transmission Owner, and any of the three entities listed in R3.1, R3.2, and R3.3 that individually or jointly owns a transmission Protection System shall each retain data ...") Response: The Response Team has replaced the RRO with RE in requirement 3 as suggested. Additionally, the team removed the Load Serving Entity and Transmission Operator based on suggestions from other commenters.
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	With respect to the FERC Order 693 directive in Paragraph 1469, the reference to the Regional Reliability Organization in R3 should be replaced with the Regional Entity.(replace "... shall each provide to its Regional Reliability Organization..." with "...shall each provide to its Regional Entity...")M1, M2, and M3 need to be changed to match R1, R2, and R3 by:(replacing "... according to the Regional Reliability Organization's procedures developed for PRC-003 R1." with "... according to the Regional Entity's procedures.")Requirement 1 refers to transmission protection systems in the case of TO's, DP's, TOP"S and LSE's while Requirement 2 specifically mentions generator protection systems in reference to GO's. In Requirement 3 however it is unclear whether Generator Owners are held responsible for generator protection systems, transmission protection systems or both. Compliance Section - Data Retention - Is the intent that GO's should retain data for an evaluation not prescribed in the Requirements - in the case of a Generator Owner evaluating transmission protection systems?Generically, in the functional model, the Transmission Operator and Load Serving Entity do

Voter	Entity	Segment	P 1469	Comments
				not own facilities and should not be included in this standard. We do not believe that R1.1, R1.2 and R1.3 are applicable to this standard and therefore should be removed. Likewise, we do not believe that R3.1, R3.2 and R3.3 are applicable to this standard and therefore should be removed.The Commission's directive is to consider adding LSE and TOPs to PRC-004-1 not to actually add them. LSEs and TOPs have no Protection Systems to coordinate. They are not equipment owners per the Functional Model. We agree that the Distribution Provider is a likely candidate for coordination. While the functional model does mention the need for Transmission Owners to develop interconnection agreements with Distribution Providers, it currently is silent on the need to coordinate Protection Systems and appears to give the responsibility for Protection Systems entirely to the Transmission Owner. We suggest that this directive should be referred to the Functional Model Working Group for a proposed resolution and modification of the functional model as necessary. Then a SAR could be developed to address to the Functional Model. Response: The Response Team has replaced the RRO with RE in requirement 3 as suggested. Additionally, the team removed the Load Serving Entity and Transmission Operator as suggested.

Summary Consideration for changes related to P1858:

Some entities suggested that R5 of the existing standard, as well as the modified standard, was inappropriate, as it dealt with issues address in the Transmission Provider's Open Access Transmission Tariff. The response Team felt that the changes proposed were appropriate, and noted that the OATT is not enforceable as a reliability standard.

Similarly, some entities suggested the PSE and LSE do not have roles in the standard. The Response Team disagreed, noting that the approved standard already included the PSE, and the LSE simply clarified the role further.

Two entities expressed concerns regarding the testing of reactive power requirements in ERCOT. The Response Team noted that this is not a standard for testing reactive power requirements, and therefore does not believe there is any conflict (as seems to be implied by the comment).

Voter	Entity	Segment	P 1858	Comments
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore Gas & Electric Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	

Voter	Entity	Segment	P 1858	Comments
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	

Voter	Entity	Segment	P 1858	Comments
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Tim Hattaway	PowerSouth Energy Cooperative	5	Abstain	
Scott Peterson	San Diego Gas & Electric	3	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Jason L. Murray	Alberta Electric System Operator	2	Approve	

Voter	Entity	Segment	P 1858	Comments
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Jason Shaver	American Transmission Co., LLC	1	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	

Voter	Entity	Segment	P 1858	Comments
Linda R. Jacobson	City of Farmington	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Danny McDaniel	Cleco Power LLC	1	Approve	
Bryan Y Harper	Cleco Utility Group	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Robert W. Roddy	Dairyland Power Coop.	1	Approve	
Dan Roethemeyer	Dynegy Inc.	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	

Voter	Entity	Segment	P 1858	Comments
Kenneth Dresner	FirstEnergy Solutions	5	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Kenneth Simmons	Gainesville Regional Utilities	3	Approve	
Guy Andrews	Georgia System Operations Corporation	4	Approve	
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	
Harold Taylor, II	GTC	1	Approve	
Bob C. Thomas	Illinois Municipal Electric Agency	4	Approve	
Jim D. Cyrulewski	JDRJC Associates	8	Approve	
Donald Gilbert	JEA	5	Approve	

Voter	Entity	Segment	P 1858	Comments
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Approve	
Charlie Martin	Louisville Gas and Electric Co.	5	Approve	
Daryn Barker	Louisville Gas and Electric Co.	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Dan R. Schoenecker	Midwest Reliability Organization	10	Approve	

Voter	Entity	Segment	P 1858	Comments
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Mark Ringhausen	Old Dominion Electric Coop.	4	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	

Voter	Entity	Segment	P 1858	Comments
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	
Philip Riley	Public Service Commission of	9	Approve	

Voter	Entity	Segment	P 1858	Comments
	South Carolina			
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Approve	
Kenneth D. Brown	Public Service Electric and Gas Co.	1	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Thomas J. Bradish	RRI Energy	5	Approve	
Trent Carlson	RRI Energy	6	Approve	
Bethany Wright	Sacramento Municipal Utility District	5	Approve	
James Leigh-Kendall	Sacramento Municipal Utility District	3	Approve	
Mike Ramirez	Sacramento Municipal Utility District	4	Approve	

Voter	Entity	Segment	P 1858	Comments
Tim Kelley	Sacramento Municipal Utility District	1	Approve	
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	
Ronald L Donahey	Tampa Electric Co.	3	Approve	

Voter	Entity	Segment	P 1858	Comments
Scott M. Helyer	Tenaska, Inc.	5	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Approve	
Jonathan Appelbaum	United Illuminating Co.	1	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
David F. Lemmons	Xcel Energy, Inc.	6	Approve	
Gregory L Pieper	Xcel Energy, Inc.	1	Approve	
Liam Noailles	Xcel Energy, Inc.	5	Approve	
Richard J. Mandes	Alabama Power Co.	3	Approve	However, this is a tariff issue and unrelated to reliability.
Anthony L Wilson	Georgia Power Co.	3	Approve	
Gwen S Frazier	Gulf Power Co.	3	Approve	
Don Horsley	Mississippi Power	3	Approve	
Horace Stephen	Southern Co. Services, Inc.	1	Approve	

Voter	Entity	Segment	P 1858	Comments
Williamson				
Louis S Slade	Dominion Resources, Inc.	6	Approve	Paragraph 1858 - We suggest striking all of R5. These requirements are contained in each Transmission Service Provider's tariff. This issue can impact reliability only when the entity substantially fails to meet its obligation under the respective OATT. . Response: R5 is included in the existing standard, and only limited changes have been proposed as part of this project. The Response Team believes the changes add clarity to the standard, and assign responsibility appropriately. The Response Team notes that the OATT is a commercial instrument, and not enforceable as a reliability standard.
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Kim Warren	Independent Electricity System Operator	2	Approve	We agree with the additional wording in Requirement R5 but there is a fundamental issue with the last part of the requirement as written. The TSP should not be the entity responsible for identifying reactive requirements. It should be the TOP that is responsible for identify this requirement. Response: The assignment to the Transmission Service Provider is contained in the original language of the standard, and this project is not proposing to change it. To the extent the industry wishes to make additional modifications to the standard, we encourage such action.
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Daniel Herring	Detroit Edison Co.	4	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	

Voter	Entity	Segment	P 1858	Comments
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Disapprove	
Saurabh Saksena	National Grid	1	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Disapprove	
Mark A. Heimbach	PPL Generation LLC	5	Disapprove	
Daniel	San Diego Gas &	5	Disapprove	

Voter	Entity	Segment	P 1858	Comments
Baerman	Electric			
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(a) R2 - load shed is not a resource but a stop gap (b) R5 - Add "for all load levels it expects to have on the TSP system" removing "controlled load, and if necessary, load shedding". (c) R5 - How does PSE arrange for load shedding? Response: These comments are related to P1879. The team has removed "load shedding" from R2, R5, and R9 based on concerns that inclusion implied that the routine use of load shedding was acceptable practice. Regarding item B, while the proposed language has merit, we do not believe it to be associated with any directive.
Edward P. Cox	AEP Marketing	6	Disapprove	AEP does not agree with expanding the scope to the LSE in R5. Furthermore, the existing applicability to the PSE is not a reliability related requirement as this service is provided by the TSP by default.We do not agree with adding "which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load, and, if necessary, load shedding - " to R5 for the PSE and LSE functions. These entities do not have many of the capabilities as listed. Response: The assignment of responsibility to the PSE is not new language; it is already part of the approved standard. Adding the LSE simply clarifies this role. The remaining comments are related to P1879. The team has removed "load shedding" from R2, R5, and R9 based on concerns that inclusion implied that the routine use of load shedding was acceptable practice.
Brock Ondayko	AEP Service Corp.	5	Disapprove	
Raj Rana	American Electric Power	3	Disapprove	

Voter	Entity	Segment	P 1858	Comments
Carolyn Ingersoll	Constellation Energy	3	Disapprove	CECD is concerned with the impact to the BA when load shedding is used as a reactive resources and feels that the standard must be modified to required the TOP notify the BA is load shedding is applied in this manner. Response: These comments are related to P1879. The team has removed "load shedding" from R2, R5, and R9 based on concerns that inclusion implied that the routine use of load shedding was acceptable practice.
Michael T. Quinn	Oncor Electric Delivery	1	Disapprove	ERCOT has a separate process for testing LSE reactive power requirements on a semi-annual basis. Market measures for reactive power are incompatible with ERCOT's philosophy to date. Response: The Response Team notes that this is not a standard for testing reactive power requirements, and therefore does not believe there is any conflict (as seems to be implied by the comment).
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. The mark-up to R9, as written, implies that load shedding can be used for first contingency conditions. This is detrimental to reliability. Response: These comments are related to P1879. The team has removed "load shedding" from R2, R5, and R9 based on concerns that inclusion implied that the routine use of load shedding was acceptable practice.
David A. Lapinski	Consumers Energy	3	Disapprove	Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot "own" facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE's suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM. Response: These comments are related to P1469. The Response Team has removed the Load Serving Entity and Transmission Operator from the standard based on stakeholder comments that indicate a more in-depth discussion is required prior to making modifications to the standard.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	

Voter	Entity	Segment	P 1858	Comments
George R. Bartlett	Entergy Corporation	1	Disapprove	Paragraph 1858 - We suggest striking all of R5. The requirement for the Transmission Customer to purchase ancillary services including voltage support, and the ability to self-supply is a tariff issue and unrelated to reliability. Response: R5 is included in the existing standard, and only limited changes have been proposed as part of this project. The Response Team believes the changes add clarity to the standard, and assign responsibility appropriately. The Response Team notes that the OATT is a commercial instrument, and not enforceable as a reliability standard.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	Regarding the LSE requirement, we're not sure that LSE's even know who the TSP is, much less their reactive requirements. The LSE probably complies with the TOP's reactive requirements. Response: The assignment to the Transmission Service Provider is contained in the original language of the standard, and this project is not proposing to change it. To the extent the industry wishes to make additional modifications to the standard, we encourage such action.
Terry L. Blackwell	Santee Cooper	1	Disapprove	Requirement 5 should be removed completely as we consider this to be tariff related and not reliability related. Response: R5 is included in the existing standard, and only limited changes have been proposed as part of this project. The Response Team believes the changes add clarity to the standard, and assign responsibility appropriately. The Response Team notes that the OATT is a commercial instrument, and not enforceable as a reliability standard.
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	We suggest striking all of R5. This is a tariff issue and unrelated to reliability. Response: R5 is included in the existing standard, and only limited changes have been proposed as part of this project. The Response Team believes the changes add clarity to the standard, and assign responsibility appropriately. The Response Team notes that the OATT is a commercial instrument, and not enforceable as a reliability standard.
Larry Akens	Tennessee Valley Authority	1	Disapprove	Requirement 5 should be removed. This is a tariff issue and unrelated to reliability. Response: R5 is included in the existing standard, and only limited changes have been proposed as part of this project. The Response Team believes the changes add clarity to the standard, and assign responsibility appropriately. The Response Team notes that the OATT is a commercial instrument, and not enforceable as a reliability standard.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	See our comments above re. addition of responsible entities.

Voter	Entity	Segment	P 1858	Comments
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	Response: Please see response above.
Jeff Nelson	Springfield Utility Board	3	Disapprove	See SUB's comment form Response: Please see the appropriate Consideration of Comments for your response.
Kevin Koloini	American Municipal Power - Ohio	4	Disapprove	Significant variability exists in transmission service agreeements which may result in difficulty meeting the power factor obligations. Does this imply that you must pay for an assessed penalty to meet compliance? Clarity on enforcement is needed. Response: The Response Team needs additional explanation to understand the comment.
Gregory Campoli	New York Independent System Operator	2	Disapprove	Taken in isolation the proposed changes to R5 are appropriate. The issue is with the requirement itself. R5 inappropriately identifies the TSP as the entity responsible for identifying reactive requirements. It should be the TOP that is responsible for identify this requirement. Response: The assignment to the Transmission Service Provider is contained in the original language of the standard, and this project is not proposing to change it. To the extent the industry wishes to make additional modifications to the standard, we encourage such action.
Thomas E Washburn	FMPP	6	Disapprove	The FERC directive does not state that load shedding should be included, and you should not plan to operate the system using load shedding in normal operations. Load shedding should only be used in emergency operation, and be covered in EOPs not here. The NERC requirement states, “which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load, and, if necessary, load shedding.” The FERC directive states that NERC should include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1. It does not say load shedding. Response: These comments are related to P1879. The team has removed “load shedding” from R2, R5, and R9 based on concerns that inclusion implied that the routine use of load shedding was acceptable practice.
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	The inclusion of the list of what is called reactive services is not appropriate without proper vetting. This is not a simple change.Also, we would note that the change allows for load shedding to support its voltage underfirst Contingency conditions; we believe this is detrimental to reliability and specifically request this be stricken. Response: The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options. The remaining comments are related to P1879. The team has removed “load shedding” from R2, R5,

Voter	Entity	Segment	P 1858	Comments
				and R9 based on concerns that inclusion implied that the routine use of load shedding was acceptable practice.
Charles H Yeung	Southwest Power Pool	2	Disapprove	The issue is with the requirement itself. R5 inappropriately identifies the TSP as the entity responsible for identifying reactive requirements. It should be the TOP that is responsible for identify this requirement. Response: The assignment to the Transmission Service Provider is contained in the original language of the standard, and this project is not proposing to change it. To the extent the industry wishes to make additional modifications to the standard, we encourage such action.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	The mark-up to R9, as written, implies that load shedding can be used for first Contingency conditions since first contingency includes single contingencies. We disagree with this change, and suggest that load shedding be removed from the requirement. In fact, the list of actions need not be included in the requirement since the inclusion of a list of reactive services is not appropriate without proper vetting. Response: The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options. The remaining comments are related to P1879. The team has removed "load shedding" from R2, R5, and R9 based on concerns that inclusion implied that the routine use of load shedding was acceptable practice.
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	The Purchase-Selling will have provisions for reactive support within the ancillary services available to it. Recommend modifying the language in requirement R5 to reflect the exercise of reactive support as provided within the ancillary services available and remove the prescriptive parts of this requirement related to the various actions that can be taken by a Transmission Operator or Transmission Service Provider. Response: The Response Team believes that acquiring appropriate Ancillary Services would qualify as arranging for reactive resources through purchase.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	We agree that the changes address paragraph 1858 but question the need for the changes or even the need for the existing requirement. This requirement is essentially a reflection of the FERC pro-forma tariff requirement that transmission customers (usually PSEs) must purchase reactive service or arrange for it themselves. Has any PSE ever arranged reactive service themselves? The transmission operator will still have to take the necessary steps to ensure reactive power is sufficient to support voltage. Response: R5 is included in the existing standard, and only limited changes have been proposed as

Voter	Entity	Segment	P 1858	Comments
				part of this project. The Response Team believes the changes add clarity to the standard, and assign responsibility appropriately. The Response Team notes that the pro forma tariff is a commercial instrument, and not enforceable as a reliability standard.

Summary Consideration for changes related to P1879:

Several entities expressed concern with the implication that load shedding was an acceptable way of providing for reactive needs during normal operations. The Response Team agreed, and removed load shedding from Requirements R2, R5, and R9.

Some entities suggested that the list of reactive services was either too limiting or implied mandatory use of all provisions. However, the language clearly indicates that the list is not all inclusive, and that none of the elements are explicitly required. As such, the Response Team believes it clarifies the standard without precluding the use of other options or mandating any specific approaches.

Some entities suggested that in some cases, the Transmission Service Provider has been incorrectly listed in the standard as the entity that identifies reactive requirements. The Response Team made no changes to the standard in this area, and the requirement contains the same language that has been previously approved by the industry. As such, the Response Team believes such a change would be out of scope for this project.

Voter	Entity	Segment	P 1879	Comments
Allen Mosher	American Public Power Association	4	Abstain	
John J. Moraski	Baltimore Gas & Electric Co.	1	Abstain	
Paul Rocha	CenterPoint Energy	1	Abstain	
Steve Alexanderson	Central Lincoln PUD	3	Abstain	
Bruce Krawczyk	ComEd	3	Abstain	
Daniel Brotzman	Commonwealth Edison Co.	1	Abstain	
Nickesha P Carrol	ConEd of NY	6	Abstain	
Christopher L de Graffenried	ConEd of NY	1	Abstain	
Wilket (Jack) Ng	ConEd of NY	5	Abstain	
Peter T Yost	ConEd of NY	3	Abstain	

Voter	Entity	Segment	P 1879	Comments
Brenda Powell	Constellation Energy Commodities Group	6	Abstain	
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Abstain	
Doug Ramey	Energy Northwest - Columbia Generating Station	5	Abstain	
Michael Korchynsky	Exelon Nuclear	5	Abstain	
Luther E. Fair	Gainesville Regional Utilities	1	Abstain	
Kenneth Simmons	Gainesville Regional Utilities	3	Abstain	
Greg Froehling	Green Country Energy	5	Abstain	
Ajay Garg	Hydro One Networks, Inc.	1	Abstain	
Michael D. Penstone	Hydro One Networks, Inc.	3	Abstain	
Rex A Roehl	Indeck Energy Services, Inc.	5	Abstain	
John W Delucca	Lee County Electric Cooperative	1	Abstain	
Daniel Duff	Liberty Electric Power LLC	5	Abstain	

Voter	Entity	Segment	P 1879	Comments
Brad Jones	Luminant Energy	6	Abstain	
Mike Laney	Luminant Generation Co. LLC	5	Abstain	
David Gordon	Massachusetts Municipal Wholesale Electric Co.	5	Abstain	
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Abstain	
Margaret Ryan	Pacific Northwest Generating Cooperative	8	Abstain	
Ronald Schloendorn	PECO Energy	1	Abstain	
Tim Hattaway	PowerSouth Energy Cooperative	5	Abstain	
Thomas J. Bradish	RRI Energy	5	Abstain	
Trent Carlson	RRI Energy	6	Abstain	
William D Shultz	Southern Co. Generation	5	Abstain	
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	
Brian Evans-Mongeon	Utility Services, Inc.	8	Abstain	
Linda Horn	Wisconsin Electric Power Co.	5	Abstain	

Voter	Entity	Segment	P 1879	Comments
James R. Keller	Wisconsin Electric Power Marketing	3	Abstain	
Anthony Jankowski	Wisconsin Energy Corp.	4	Abstain	
James A Ziebarth	Y-W Electric Association, Inc.	4	Abstain	
Edward P. Cox	AEP Marketing	6	Approve	
Brock Ondayko	AEP Service Corp.	5	Approve	
Jason L. Murray	Alberta Electric System Operator	2	Approve	
Rodney Phillips	Allegheny Power	1	Approve	
Bob Reeping	Allegheny Power	3	Approve	
Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4	Approve	
Raj Rana	American Electric Power	3	Approve	
Jason Shaver	American Transmission Co., LLC	1	Approve	
Mel Jensen	APS	5	Approve	
Robert D Smith	Arizona Public Service Co.	1	Approve	
James V. Petrella	Atlantic City Electric Co.	3	Approve	

Voter	Entity	Segment	P 1879	Comments
Eric Egge	Black Hills Corp	1	Approve	
Brenda S. Anderson	Bonneville Power Administration	6	Approve	
Donald S. Watkins	Bonneville Power Administration	1	Approve	
Francis J. Halpin	Bonneville Power Administration	5	Approve	
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
Timothy VanBlaricom	California ISO	2	Approve	
John Yale	Chelan County Public Utility District #1	5	Approve	
Linda R. Jacobson	City of Farmington	3	Approve	
Gregg R Griffin	City of Green Cove Springs	3	Approve	
Alan Gale	City of Tallahassee	5	Approve	
Randall McCamish	City of Vero Beach	1	Approve	
Danny McDaniel	Cleco Power LLC	1	Approve	
Bryan Y Harper	Cleco Utility Group	3	Approve	
Paul Morland	Colorado Springs Utilities	1	Approve	

Voter	Entity	Segment	P 1879	Comments
Bob Essex	Cowlitz County PUD	5	Approve	
Russell A Noble	Cowlitz County PUD	3	Approve	
Rick Syring	Cowlitz County PUD	4	Approve	
Dan Roethemeyer	Dynegy Inc.	5	Approve	
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	
Kenneth Dresner	FirstEnergy Solutions	5	Approve	
Kevin Querry	FirstEnergy Solutions	3	Approve	
Mark S Travaglianti	FirstEnergy Solutions	6	Approve	
Dennis Minton	Florida Keys Electric Cooperative Assoc.	1	Approve	
Frank Gaffney	Florida Municipal Power Agency	4	Approve	
Lee Schuster	Florida Power Corporation	3	Approve	
Thomas W. Richards	Fort Pierce Utilities Authority	4	Approve	
Bob C.	Illinois Municipal	4	Approve	

Voter	Entity	Segment	P 1879	Comments
Thomas	Electric Agency			
Kim Warren	Independent Electricity System Operator	2	Approve	
Donald Gilbert	JEA	5	Approve	
Walt Gill	Lake Worth Utilities	1	Approve	
Larry E Watt	Lakeland Electric	1	Approve	
Mace Hunter	Lakeland Electric	3	Approve	
Doug Bantam	LES	1	Approve	
Dennis Florom	LES	5	Approve	
Eric Ruskamp	LES	6	Approve	
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Approve	
Daniel Prowse	Manitoba Hydro	6	Approve	
Greg C Parent	Manitoba Hydro	3	Approve	
Michelle Rheault	Manitoba Hydro	1	Approve	
Steven Grego	MEAG Power	3	Approve	
Terry Harbour	MidAmerican Energy Co.	1	Approve	
Dan R. Schoenecker	Midwest Reliability Organization	10	Approve	

Voter	Entity	Segment	P 1879	Comments
Randi Woodward	Minnesota Power, Inc.	1	Approve	
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Approve	
John Bos	Muscatine Power & Water	3	Approve	
John Canavan	NorthWestern Energy	1	Approve	
David T. Anderson	Ocala Electric Utility	3	Approve	
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	
Terri Pyle	Oklahoma Municipal Power Authority	4	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	
Bruce Glorvigen	OTP Wholesale Marketing	6	Approve	
Bradley Tollerson	OTP Wholesale Marketing	3	Approve	
Lawrence R. Larson	Otter Tail Power Co.	1	Approve	
Stacie Hebert	Otter Tail Power Co.	5	Approve	
Chifong L. Thomas	Pacific Gas and Electric Co.	1	Approve	

Voter	Entity	Segment	P 1879	Comments
John Apperson	PacifiCorp	3	Approve	
Mark Sampson	PacifiCorp	1	Approve	
Sandra L. Shaffer	PacifiCorp	5	Approve	
Terry L Baker	Platte River Power Authority	3	Approve	
John C. Collins	Platte River Power Authority	1	Approve	
Frank F. Afranji	Portland General Electric Co.	1	Approve	
Richard J Kafka	Potomac Electric Power Co.	1	Approve	
Brenda L Truhe	PPL Electric Utilities Corp.	1	Approve	
Mark A. Heimbach	PPL Generation LLC	5	Approve	
James Eckelkamp	Progress Energy	6	Approve	
Wayne Lewis	Progress Energy Carolinas	5	Approve	
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	
David Murray	PSEG Power LLC	5	Approve	
Laurie Williams	Public Service Co. of New Mexico	1	Approve	

Voter	Entity	Segment	P 1879	Comments
Philip Riley	Public Service Commission of South Carolina	9	Approve	
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Approve	
Kenneth D. Brown	Public Service Electric and Gas Co.	1	Approve	
Kenneth R. Johnson	Public Utility District No. 1 of Chelan County	3	Approve	
Henry E. LuBean	Public Utility District No. 1 of Douglas County	4	Approve	
John D. Martinsen	Public Utility District No. 1 of Snohomish County	4	Approve	
Greg Lange	Public Utility District No. 2 of Grant County	3	Approve	
Bethany Wright	Sacramento Municipal Utility District	5	Approve	
James Leigh-Kendall	Sacramento Municipal Utility District	3	Approve	
Mike Ramirez	Sacramento Municipal Utility District	4	Approve	
Tim Kelley	Sacramento Municipal Utility	1	Approve	

Voter	Entity	Segment	P 1879	Comments
	District			
Glen Reeves	Salt River Project	5	Approve	
John T. Underhill	Salt River Project	3	Approve	
Robert Kondziolka	Salt River Project	1	Approve	
Scott Peterson	San Diego Gas & Electric	3	Approve	
Dana Wheelock	Seattle City Light	3	Approve	
Dennis Sismaet	Seattle City Light	6	Approve	
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
Steven R Wallace	Seminole Electric Cooperative, Inc.	4	Approve	
Trudy S. Novak	Seminole Electric Cooperative, Inc.	6	Approve	
Richard Jones	South Carolina Electric & Gas Co.	5	Approve	
Richard McLeon	South Texas Electric Cooperative	1	Approve	
Charles H Yeung	Southwest Power Pool	2	Approve	
RJames Rocha	Tampa Electric Co.	5	Approve	

Voter	Entity	Segment	P 1879	Comments
Ronald L Donahey	Tampa Electric Co.	3	Approve	
Scott M. Helyer	Tenaska, Inc.	5	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Approve	
Brandy A Dunn	Western Area Power Administration	1	Approve	
Louise McCarren	Western Electricity Coordinating Council	10	Approve	
Louis S Slade	Dominion Resources, Inc.	6	Approve	1879 - R2 and R9 - We suggest striking the insertions. In R8 we suggest striking "- which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding -". This makes the standard resource neutral, which is apparently the aim of FERC. Response: Thank you for your supportive comment. The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options. The Response Team has removed reference to load shedding from R2, R5, and R9.
Mike Garton	Dominion Resources, Inc.	5	Approve	
John K Loftis	Dominion Virginia Power	1	Approve	
Michael F Gildea	Dominion Resources Services	3	Approve	
Michael T. Quinn	Oncor Electric Delivery	1	Approve	Not a problem to allow it as permissible. Oncor has enough reactive resource capability already without acquiring additional controllable loads (e.g. reactive generation scheduling; transmission line and reactive resource switching and, if necessary, load shedding. Response: Thank you for your supportive comment.
Mark Peters	Ameren Services	3	Disapprove	
Sam Dwyer	Amerenue	5	Disapprove	

Voter	Entity	Segment	P 1879	Comments
Brian Conroy	Central Maine Power Co.	1	Disapprove	
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Disapprove	
Robert W. Roddy	Dairyland Power Coop.	1	Disapprove	
Daniel Herring	Detroit Edison Co.	4	Disapprove	
Robert Smith	Duke Energy	5	Disapprove	
Henry Ernst-Jr	Duke Energy Carolina	3	Disapprove	
Walter Yeager	Duke Energy Carolina	6	Disapprove	
George S. Carruba	East Kentucky Power Coop.	1	Disapprove	
Sally Witt	East Kentucky Power Coop.	3	Disapprove	
Stephen Ricker	East Kentucky Power Coop.	5	Disapprove	
Jim D. Cyrulewski	JDRJC Associates	8	Disapprove	
Charlie Martin	Louisville Gas and Electric Co.	5	Disapprove	
Daryn Barker	Louisville Gas and Electric Co.	6	Disapprove	
Saurabh	National Grid	1	Disapprove	

Voter	Entity	Segment	P 1879	Comments
Saksena				
Gregory Campoli	New York Independent System Operator	2	Disapprove	
Michael Schiavone	Niagara Mohawk (National Grid Co.)	3	Disapprove	
Michael K Wilkerson	Northern Indiana Public Service Co.	5	Disapprove	
Robert Mattey	Ohio Valley Electric Corp.	1	Disapprove	
Douglas G Peterchuck	Omaha Public Power District	1	Disapprove	
Daniel Baerman	San Diego Gas & Electric	5	Disapprove	
Steve McElhaney	South Mississippi Electric Power Association	4	Disapprove	
Jerry W Johnson	South Mississippi Electric Power Association	5	Disapprove	
Barry Ingold	Tri-State G & T Association Inc.	5	Disapprove	
Keith V. Carman	Tri-State G & T Association Inc.	1	Disapprove	
David F. Lemmons	Xcel Energy, Inc.	6	Disapprove	
Gregory L Pieper	Xcel Energy, Inc.	1	Disapprove	

Voter	Entity	Segment	P 1879	Comments
Liam Noailles	Xcel Energy, Inc.	5	Disapprove	
Kirit S. Shah	Ameren Services	1	Disapprove	(a) R2 - load shed is not a resource but a stop gap (b) R5 - Add "for all load levels it expects to have on the TSP system" removing "controlled load, and if necessary, load shedding". (c) R5 - How does PSE arrange for load shedding? Response: The Response Team has removed reference to load shedding from R2, R5, and R9. Regarding item B, while the proposed language has merit, we do not believe it to be associated with any directive.
George R. Bartlett	Entergy Corporation	1	Disapprove	1879 - R2 and R9 - We suggest striking the insertions. In R8 we suggest striking "- which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding -". This makes the standard resource neutral, which is apparently the aim of FERC. Including a partial list of resources that qualify as reactive resources, does not improve the reliability of the standard. Response: Thank you for your supportive comment. The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options. The Response Team has removed reference to load shedding from R2, R5, and R9.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	
Mark Ringhausen	Old Dominion Electric Coop.	4	Disapprove	Agree with SoCal that a blanket allowance of reduce reactive support because of DSM must not be assumed. Response: The Response Team agrees that a blanket allowance of reduced reactive support because of DSM must not be assumed.
Carolyn Ingersoll	Constellation Energy	3	Disapprove	CECD is concerned with the impact to the BA when load shedding is used as a reactive resources and feels that the standard must be modified to required the TOP notify the BA is load shedding is applied in this manner. Response: The Response Team has removed reference to load shedding from R2, R5, and R9.
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	comments will be filed via the formal comment form Response: Please see the Consideration of Comments for responses.
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	disagrees with including load shed in R2. R2 is in a planning horizon versus R8 and R9 which is in real-time operating horizon. United Illuminating does not believe it is appropriate PLAN on load shed to meet a reactive requirement. Load shed (R8 and R9) is appropriate in the real time environment to protect the BES.

Voter	Entity	Segment	P 1879	Comments
				Response: The Response Team has removed reference to load shedding from R2, R5, and R9.
Larry Akens	Tennessee Valley Authority	1	Disapprove	For Requirements 2 and 9, the insertions should be struck. For Requirement 8 "which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding." Response: The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options. The Response Team has removed reference to load shedding from R2, R5, and R9.
George T. Ballew	Tennessee Valley Authority	5	Disapprove	For Requirements 2 and 9, the insertions should be struck. For Requirement 8 "which may include, but is not limited to, reactive generation scheduling; transmssion line and reactive resource switching; controllable load; and, if necessary, load shedding." Response: The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options. The Response Team has removed reference to load shedding from R2, R5, and R9.
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	R2 and R9 – We suggest striking the insertions. In R8 we suggest striking "– which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding –". Response: The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options. The Response Team has removed reference to load shedding from R2, R5, and R9.
Richard J. Mandes	Alabama Power Co.	3	Disapprove	In R9, shedding load following the first contingency would seem to violateTPL-002, Category B events. Response: The Response Team has removed reference to load shedding from R2, R5, and R9.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	

Voter	Entity	Segment	P 1879	Comments
David H. Boguslawski	Northeast Utilities	1	Disapprove	Inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement is inappropriate. This results in a "HOW" to meet the requirements instead of "WHAT" to meet the requirements. The development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome. The mark-up to R9, as written, implies that load shedding can be used for first contingency conditions. This is detrimental to reliability. Response: The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options. The Response Team has removed reference to load shedding from R2, R5, and R9.
David A. Lapinski	Consumers Energy	3	Disapprove	Load-serving entity and Transmission Operators, according to the Glossary of Terms and the Functional Model (FM), are OPERATOR entities, not OWNER entities. Fundamentally, they cannot "own" facilities as described in R1 and R3. The corresponding OWNER entities, the Distribution Provider and Transmission Owner, were already included in the standard. In many cases, the LSE and DP will be the same corporate organization, as will be Transmission Operator and Transmission Owner, but the Applicable Entities refer to entities as described in the Glossary and in the FM. We recommend that NERC respond to the Commission that they considered ISO-NE's suggestion, and elected to NOT include these entities, with related reference to both the Glossary and to the FM. Response: The Response Team believes this comment is related to P1469. In response to stakeholder comments, the Load Serving Entity and Transmission Operator have been removed from the standard, as the Response Team believes that further in-depth discussion will be needed prior to making such modifications.
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	Paragraph 1879 of Order 693 doesn't say anything about load shedding, and we believe that it is especially inappropriate to include load shedding in R2 and R5. While you may use load shedding to correct a reactive problem (i.e. R8 and R9), we don't believe that you should be planning on using it. In addition, we believe that the inclusion of controllable loads as a resource to correct reactive balance problems falls outside any current language in our interruptible rate plans. The only trigger now is based on energy deficiencies or on a cost structure. The addition of controllable load without a scaling attribute leaves a disconnect. This equates the shedding of a pocket of load as an action you could take in lieu of switching a capacitor. True, both are reserves, but most entities probably would not shed load to protect voltage levels under normal conditions. Smaller LSEs may find it more economical to employ load shed as a reactive resource in lieu of the cost of a capacitor. The standard

Voter	Entity	Segment	P 1879	Comments
				needs to be more definitive in terms of resources and severity levels. Controllable loads and load shedding should be coupled with a resultant contingency action and parsed from the normal responsive reactive resource pool. Controllable load as a resource to correct reactive balance problems is not comparable to a capacitor under normal conditions and should not be construed as such.Would this revised standard force entities to use controllable loads to correct problems? Would entities be seen as non-compliant if they did not exercise that option if there were no trigger points in their contracts for such? We suggest moving "controllable load" to after the "and, if necessary," phrase in R2, R5, R8 and R9 to indicate that it should be a last resort, not used with the same regularity as the other resources listed. Also, we suggest that a term be defined for controllable load contracted for such service. Response: The language indicates that this list is not all inclusive, nor is it a requirement to support all the items in the list. As such, the Response Team believes it clarifies the standard without precluding the use of other options or mandating specific options. The Response Team has removed reference to load shedding from R2, R5, and R9. Additional comment on R5 : Duke Energy has concerns that multiple registered LSEs within our foot print have to be responsive to their own concern. An auditor may imply that our response is that of all LSEs within the metered boundary of the BA and that is not the case. The requirement should be revised to clearly indicate that each registered LSE's responses to requirements in VAR-001 are pertinent to only that entity, with no implication of purview over other registered LSEs within the physical boundary of the system. Response: The standard currently specifies that the requirement applies to EACH entity. As such, the Response Team believes that your concern is addressed within the current language. We are concerned that the Levels of Non Compliance have been removed and that the Violation Severity Levels states that there is "no change" but all information following that statement have been removed from the Standard. What are the Violation Severity Levels being based on? The current compliance levels were removed by mistake and should be retained. Response: VSLs have replaced Levels of Non-Compliance, and the existing VSLs posted on the NERC website do not conflict with the modifications to the standard.
Terry L. Blackwell	Santee Cooper	1	Disapprove	Recommend removing the insertions in Requirement 2 and Requirement 9. We recommend removing Requirement 5 completely for the reason stated above. Requirement 8 we recommend removing all the wording between the dashses. Response: The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options.

Voter	Entity	Segment	P 1879	Comments
				R5 is included in the existing standard, and only limited changes have been proposed as part of this project. The Response Team believes the changes add clarity to the standard, and assign responsibility appropriately. The Response Team notes that the OATT is a commercial instrument, and not enforceable as a reliability standard. The Response Team has removed reference to load shedding from R2, R5, and R9.
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	Recommended changes to the proposed requirements prevent supporting the VSL proposed changes. Response: The Response Team needs additional explanation to understand the comment.
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	
Jeff Nelson	Springfield Utility Board	3	Disapprove	See SUB's comment form Response: Please see the appropriate "Consideration of Comments" for response.
Kevin Koloini	American Municipal Power - Ohio	4	Disapprove	Significant variability exists in transmission service agreeements which may result in difficulty meeting the power factor obligations. Does this imply that you must pay for an assessed penalty to meet compliance? Clarity on enforcement is needed. Response: The Response Team needs additional explanation to understand the comment.
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	Taken in isolation the proposed changes to R5 are appropriate. The issue is with the requirement itself. R5 inappropriately identifies the TSP as the entity responsible for identifying reactive requirements. It should be the TOP that is responsible for identify this requirement. Response: The assignment to the Transmission Service Provider is contained in the original language of the standard, and this project is not proposing to change it. To the extent the industry wishes to make additional modifications to the standard, we encourage such action.
Thomas E Washburn	FMPP	6	Disapprove	The FERC directive does not state that load shedding should be included, and you should not plan to operate the system using load shedding in normal operations. Load shedding should only be used in emergency operation, and be covered in EOPs not here. The NERC requirement states, "which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load, and, if necessary, load shedding." The FERC directive states that NERC should include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1. It does not say load shedding. Response: The Response Team has removed reference to load shedding from R2, R5, and R9.
Guy Andrews	Georgia System	4	Disapprove	We disagree with the inclusion of load shedding as a resource in VAR-001 R2, R5, and R9. Controllable

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>P 1879</th><th>Comments</th></tr>
<tr><td></td><td>Operations Corporation</td><td></td><td></td><td rowspan="3">load is certainly a resource and that is what FERC directed to be included. Load shedding is certainly an appropriate action to be included in requirement R8, but considering load shedding (as distinct from controllable load) as a resource would only allow an entity to carry less true resources to meet the requirement. Perversely the inclusion of load shedding as a resource would make it difficult to violate the requirement, because an entity would always have sufficient load shedding resources (you can shed your entire load in theory).
Response: The Response Team has removed reference to load shedding from R2, R5, and R9.</td></tr>
<tr><td>R Scott S. Barfield-McGinnis</td><td>Georgia System Operations Corporation</td><td>3</td><td>Disapprove</td></tr>
<tr><td>Harold Taylor, II</td><td>GTC</td><td>1</td><td>Disapprove</td></tr>
<tr><td>Kathleen Goodman</td><td>ISO New England, Inc.</td><td>2</td><td>Disapprove</td><td>We, as a general matter, oppose inclusion or exclusion of specific technologies that may or may not be used to fulfill a requirement. We believe this results in a “HOW” to meet a requirement instead of “WHAT” to meet the requirements and, have, in the past opposed such specifications within the Standards. Also, we believe development of a standard to allow for additional technologies requires a much more significant effort and would need to include many industry experts to achieve the goal to enhance reliability and make sure the opposite (reduction in reliability) is not the ultimate outcome.
Response: The language indicates that this list is not all inclusive. As such, the Response Team believes it clarifies the standard without precluding the use of other options.</td></tr>
<tr><td>Joseph O'Brien</td><td>Northern Indiana Public Service Co.</td><td>6</td><td>Disapprove</td><td>What's up with the semicolons?
Response: While commas are normally used to separate items in a series, semicolons can be used between series items when the series items themselves contain commas.</td></tr>
<tr><td>Jason L Marshall</td><td>Midwest ISO, Inc.</td><td>2</td><td>Disapprove</td><td>While changes to R2, R5, R8 and R9 may address the Commission directives in paragraph 1879, we do not agree with the changes and believe a better solution is available. Rather than adding a laundry list of methods to control voltage, we suggest the requirements should be silent on the methods. Thus, we suggest that the additions to R2, R5, R8 and R9 be removed and that “reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding” be struck from R8. In this way, Commission’s goal of ensuring the reliability standards do not prevent Commission policy from being implemented is met. The proposed changes appear to be using Reliability Standards to further Commission policy on demand response which is surely not their intent since Reliability Standards are about maintaining a reliable grid.We agree that no changes are necessary to the standard to address SoCal Edison’s concerns in paragraph 1879. NERC simply needs to offer their explanation in the regulatory filing
Response: Thank you for your supportive comment.
Regarding the concern with the list of methods, the language indicates that this list is not all inclusive.</td></tr>
</table>

Voter	Entity	Segment	P 1879	Comments
				As such, the Response Team believes it clarifies the standard without precluding the use of other options.

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Standards Announcement

Recirculation Ballot Windows Open
July 21–July 31, 2010

Project 2010-12: Order 693 Directives

A recirculation ballot window for proposed standards from the Order 693 Directives is now open **until 8 p.m. Eastern on July 31, 2010.**

Instructions

Members of the ballot pool were sent a private e-mail invitation (along with reminder copies) to vote on the ballots associated with this project. The e-mail invitations contain a link to the set of ballots and specific instructions for using this balloting approach.

Please use the link in those e-mails to connect to the recirculation ballots.

Recirculation Ballot Process

The Standards Committee encourages all members of the ballot pool to review the consideration of comments submitted with the initial ballots as well as the consideration of comments submitted through the public comment period. 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

On March 18, 2010, FERC issued several orders and notices of proposed rulemakings pertaining to standards development activities and processes, suggesting a lack of progress in responding to directives from Order 693 as well in the timeliness of standards development in general. At the May 2010 NERC Board meeting, Gerry Cauley, NERC's President, also expressed these concerns, indicating that the resolution to these concerns is one of NERC's top priorities in the near term. In an effort to be more responsive, the Standards Committee approved having NERC assemble a team of experts to assist in reviewing the directives and identifying those which had a significant chance of being non-controversial; i.e., could be modified, balloted, and filed in a very short amount of time.

The Standards Committee approved the following deviations from the standards development process:

- Post the SAR and proposed revisions for a formal shortened comment period (June 18–July 13, 2010)
- Form the ballot pool during the first 15 days of the comment period (June 18–July 2, 2010)
- Conduct an initial 10-day ballot on a line-item basis (July 2–13, 2010)

- Require the withdrawal from balloting any item that has significant disagreement from stakeholders as evidenced in comments and ballot results
- Allow modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard (recirculation ballot July 20–30, 2010)

That team identified 34 directives related to 13 standards as candidates for inclusion in this process. Changes to the standards were developed to address the directives, and the directives were posted for comment and initial ballot. During this time, the Standards Committee created a special Response Team for the project, comprised of the original NERC team of experts and the chairs and vice-chairs of drafting team working on projects related to the standards being modified.

Following the review of the comments received and the results of the initial Ballot, the Response Team has identified six standards addressing several directives from FERC Order No 693 that will be moving forward to recirculation ballot. The six standards and the paragraphs in Order No. 693 containing those directives are as follows:

- BAL-002-1 — Disturbance Control Performance (¶ 321)
- EOP-002-3 — Capacity and Energy Emergencies; (¶ 577, 582)
- FAC-002-1 — Coordination of Plans for New Generation, Transmission, and End-User Facilities; (¶ 693)
- MOD-021-2 — Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts; (¶ 1300)
- PRC-004-2 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations; (¶ 1469)
- VAR-001-2 — Voltage and Reactive Control. (¶ 1858, 1879)

The remaining changes have been determined to be too controversial to move forward within the framework of the current project. As such, they have been withdrawn from consideration as part of the balloting associated with Project 2010-12.

More information can be following project page: http://www.nerc.com/filez/standards/Project2010-12_Order-693_Directives.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

Several changes were made to the BAL-002 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
321	The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary.	BAL-002-1	DELETED SENTENCES IN R4.2 AND R6.2 THAT ALLOWED CHANGES WITH OC APPROVAL.
321	As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.	BAL-002-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION
330	We direct the ERO to submit a modification to BAL-002-0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.	BAL-002-1	WITHDRAWN FROM BALLOT
335	Accordingly, the Commission directs the ERO to explicitly allow DSM as a resource for contingency reserves, and clarifies that DSM should be treated on a comparable basis and must meet similar technical requirements as other resources providing this service.	BAL-002-1	WITHDRAWN FROM BALLOT
1232	We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.	BAL-002-1	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

1. **Changes for directives in Paragraph 321** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

   Comments:

2. **WITHDRAWN FROM BALLOT**
3. **WITHDRAWN FROM BALLOT**
4. **WITHDRAWN FROM BALLOT**

Several changes were made to the BAL-005 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
404	The Commission clarifies that its direction to the ERO in this section is for it to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct control load management as regulating reserves, subject to the clarifications provided in this section.	BAL-005-1	WITHDRAWN FROM BALLOT
415	Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission's proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO's Work Plan. 410. Xcel requests that the Commission reconsider Requirement R17 of this Reliability Standard stating that the accuracy ratings for older equipment (current and potential transformers) may be difficult to determine and may require the costly replacement of this older equipment on combustion turbines and older units while adding little benefit to reliability. Xcel states that the Commission should clarify that Requirement R17 need only apply to interchange metering of the balancing area in those cases where errors in generating metering are captured in the imbalance responsibility calculation of the balancing area. 411. FirstEnergy states that Requirement R17 should include only "control center devices" instead of devices at each substation. FirstEnergy states that accuracy at the substation level is unnecessary and the costs to install automatic generation control equipment at each substation would be high. FirstEnergy also states that the term "check" in Requirement R17 needs to be clarified.	BAL-005-1	WITHDRAWN FROM BALLOT

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management	BAL-005-1	WITHDRAWN FROM BALLOT
420	The Commission approves Reliability Standard BAL-005-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to BAL-005-0 through the Reliability Standards development process that clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using nonfarm service	BAL-005-1	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

5. **WITHDRAWN FROM BALLOT**
6. **WITHDRAWN FROM BALLOT**
7. **WITHDRAWN FROM BALLOT**
8. **WITHDRAWN FROM BALLOT**
9. **WITHDRAWN FROM BALLOT**
10. **WITHDRAWN FROM BALLOT**

Several changes were made to the EOP-001 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
565	The Commission agrees with ISO-NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.	EOP-001-2	WITHDRAWN FROM BALLOT – ALREADY ADDRESSED IN PREVIOUS VERSION OF STANDARD.
571	As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that "insufficient transmission capability" could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.	EOP-001-2	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

11. **WITHDRAWN FROM BALLOT**
12. **WITHDRAWN FROM BALLOT**
13. **WITHDRAWN FROM BALLOT**

Several changes were made to the EOP-002 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
577	A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.	EOP-002-3 (No changes to standard)	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION – BELIEVED TO ALREADY BE ADDRESSED IN IRO-006-4, SO NO CHANGES TO STANDARD NEEDED.
582	Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. 579. ISO-NE states that Requirement R2 essentially requires the same actions covered by ISO-NE Operating Procedure No. 4. ISO-NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO-NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO-NE procedures. ISO-NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.	EOP-002-3	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION FOR THIS PORTION OF PARAGRAPH 582. MODIFIED MEASURE M5 PER COMMENTERS SUGGESTIONS.
582	Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.	EOP-002-3	MODIFIED MEASURE M5 PER COMMENTERS SUGGESTIONS.

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
573	Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.	EOP-002-3	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

14. Changes for directives in Paragraph 577 ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

15. Changes for directives in Paragraph 582 ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

16. WITHDRAWN FROM BALLOT

17. WITHDRAWN FROM BALLOT

Several changes were made to the EOP-003 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
601	We also note that APPA raise(s) issues regarding coordination of trip settings and automatic and manual load shedding plans. The Commission directs the ERO to consider these comments in future modification to the Reliability Standard through the Reliability Standards development process. 598 In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners.	EOP-003-2	WITHDRAWN FROM BALLOT
603	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-003-1 through the Reliability Standards development process that requires periodic drills of simulated load shedding.	EOP-003-2	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

18. WITHDRAWN FROM BALLOT

19. WITHDRAWN FROM BALLOT

20. WITHDRAWN FROM BALLOT

Several changes were made to the EOP-004 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
612	APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.	EOP-004-2	WITHDRAWN FROM BALLOT
615	The Commission declines to address Xcel's concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process. 608. Xcel expresses concern regarding what constitutes a reportable event for each applicable entity and recommends that the Reliability Standard be revised to define what a reportable event is for each entity that has reporting obligations. Further, Xcel states that the requirement in Requirement R3.4 for a final report within 60 days may not be feasible given the current WECC process, which among other things, requires the creation of a group to prepare the report and a 30-day posting of a draft report before it becomes final. Xcel also states that if the ultimate purpose of the report is to provide information to avoid a recurrence of a system disturbance, then the Reliability Standard should be revised to require the distribution of the report to similarly situated entities.	EOP-004-2	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

21. **WITHDRAWN FROM BALLOT**
22. **WITHDRAWN FROM BALLOT**
23. **WITHDRAWN FROM BALLOT**

A change was made to the FAC-002 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
693	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.	FAC-002-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION

Please indicate your vote for the following changes:

24. Changes for directives in Paragraph 693 ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

Several changes were made to the MOD-017 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
1249	The Commission also directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values. In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.	MOD-017-1	WITHDRAWN FROM BALLOT
1250	We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.	MOD-017-1	WITHDRAWN FROM BALLOT
1251	The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.	MOD-017-1	WITHDRAWN FROM BALLOT
1252	The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement	MOD-017-1	WITHDRAWN FROM BALLOT

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
	that addresses correcting forecasts based on prior inaccuracies, errors and bias.		
1255	We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.	MOD-017-1	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

25. **WITHDRAWN FROM BALLOT**
26. **WITHDRAWN FROM BALLOT**
27. **WITHDRAWN FROM BALLOT**
28. **WITHDRAWN FROM BALLOT**
29. **WITHDRAWN FROM BALLOT**
30. **WITHDRAWN FROM BALLOT**
31. **WITHDRAWN FROM BALLOT**
32. **WITHDRAWN FROM BALLOT**
33. **WITHDRAWN FROM BALLOT**

Several changes were made to the MOD-019 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
1276	The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	MOD-019-1	WITHDRAWN FROM BALLOT
1277	We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.	MOD-019-1	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

34. **WITHDRAWN FROM BALLOT**
35. **WITHDRAWN FROM BALLOT**
36. **WITHDRAWN FROM BALLOT**

Several changes were made to the MOD-020 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
1287	We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern.	MOD-020-1	WITHDRAWN FROM BALLOT

Please indicate your vote for the following changes:

37. WITHDRAWN FROM BALLOT

38. WITHDRAWN FROM BALLOT

Changes were made to the MOD-021 standard to address one FERC directive:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
1300	The Commission directs the ERO to modify the title and purpose statement to remove the word "controllable." We note that no commenter disagrees.	MOD-021-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION

Please indicate your vote for the following changes:

39. Changes for directives in Paragraph 1300 ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

Several changes were made to the PRC-004 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
1469	Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.	PRC-004-2	REFERENCES TO RRO IN R3 AND M3 CORRECTED. LSE AND TOP HAVE BEEN REMOVED. OTHERWISE, NO CHANGE FROM PREVIOUSLY BALLOTED VERSION.
1469	We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.	PRC-004-2	THESE CHANGES REMOVED FROM THE STANDARD. LSE AND TOP HAVE BEEN REMOVED.

Please indicate your vote for the following changes:

40. Changes for directives in Paragraph 1469 ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

Comments:

Several changes were made to the VAR-001 standard to address FERC directives:

Paragraph	Directive Language	Standard No.	RESPONSE TEAM COMMENTS
1858	The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	VAR-001-2	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION
1879	The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1.	VAR-001-2	LOAD SHEDDING REMOVED FROM R2, R5, AND R9.
1879	While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements. 1878. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.	VAR-001-2 (No changes to standard)	LOAD SHEDDING REMOVED FROM R2, R5, AND R9. OTHERWISE, NO CHANGE FROM PREVIOUSLY BALLOTED VERSION – RESPONSE TEAM BELIEVES NO CHANGES ARE NEEDED TO ADDRESS SOCAL EDISON AND SMA COMMENTS

Please indicate your vote for the following changes:

41. **Changes for directives in Paragraph 1858** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

42. **Changes for directives in Paragraph 1879** ☐ **Approve** ☐ **Disapprove** ☐ **Abstain**

    Comments:

Ballot Results	
Ballot Name:	Project 2010-12: Order 693 Directives[1]
Ballot Period:	7/21/10 - 7/31/10
Ballot Type:	Recirculation
Total # Votes:	235
Total Ballot Pool:	295
Quorum:	79.66%
Weighted Segment Vote:	See below (multiple ballots)
Ballot Results:	The ballots have passed.

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
321	The Commission adopts the NOPR's proposal to require the ERO to develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2. The ERO has the responsibility to assure the reliability of the Bulk-Power System and should be the entity that modifies the Disturbance Recovery Period as necessary.	82.44%	BAL-002-1	DELETED SENTENCES IN R4.2 AND R6.2 THAT ALLOWED CHANGES WITH OC APPROVAL.
321	As identified in the Applicability Issues section, the Commission directs the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.		BAL-002-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION

[1] Conducted as multiple ballots

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
577	A number of commenters agree that the TLR procedure is an inappropriate and ineffective tool for mitigating actual IROL violations or for use in emergency situations. On the other hand, International Transmission believes the TLR procedure can be an appropriate and effective tool to mitigate IROL violations or for use in emergency situations and MISO argues that operators should not be precluded from implementing the TLR procedure during emergencies. The Commission disagrees. As explained in the NOPR and in the Blackout Report, actions undertaken under the TLR procedure are not fast and predictable enough for use in situations in which an operating security limit is close to being, or actually is being, violated. As such the Commission cannot agree with International Transmission and MISO. However, the Commission agrees with APPA, EEI, Entergy and MidAmerican that the TLR procedure may be appropriate and effective for use in managing potential IROL violations. Accordingly, the Commission will maintain its direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.	96.60%	EOP-002-3 (No changes to standard)	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION – BELIEVED TO ALREADY BE ADDRESSED IN IRO-006-4, SO NO CHANGES TO STANDARD NEEDED.
582	Accordingly, the Commission directs that the ERO, through the Reliability Standards development process, address ISO-NE's concern. 579. ISO-NE states that Requirement R2 essentially requires the same actions covered by ISO-NE Operating Procedure No. 4. ISO-NE is concerned that a strict approach to auditing compliance with the Reliability Standard could result in a finding that ISO-NE was in violation of the Reliability Standard if it skipped a particular action under its emergency plan even though that action was not called for under ISO-NE procedures. ISO-NE requests that the Commission direct NERC to clarify that a system operator has discretion not to implement every action specified in its capacity and energy emergency plans when other appropriate actions are possible.	80.02%	EOP-002-3	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION FOR THIS PORTION OF PARAGRAPH 582. MODIFIED MEASURE M5 PER COMMENTERS SUGGESTIONS.

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
582	Further, we direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard.		EOP-002-3	MODIFIED MEASURE M5 PER COMMENTERS SUGGESTIONS.
693	In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.	80.11%	FAC-002-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION
1300	The Commission directs the ERO to modify the title and purpose statement to remove the word “controllable.” We note that no commenter disagrees.	96.17%	MOD-021-1	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION
1469	Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.	78.94%	PRC-004-2	REFERENCES TO RRO IN R3 AND M3 CORRECTED. LSE AND TOP HAVE BEEN REMOVED. OTHERWISE, NO CHANGE FROM PREVIOUSLY BALLOTED VERSION.
1469	We direct the ERO to consider ISO-NE’s suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.		PRC-004-2	THESE CHANGES REMOVED FROM THE STANDARD. LSE AND TOP HAVE BEEN REMOVED.
1858	The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	74.65%	VAR-001-2	NO CHANGE FROM PREVIOUSLY BALLOTED VERSION
1879	The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1.	72.85%	VAR-001-2	LOAD SHEDDING REMOVED FROM R2, R5, AND R9.

Paragraph	Directive Language	Weighted Segment Approval	Standard No.	RESPONSE TEAM COMMENTS
1879	While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements. 1878. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.		VAR-001-2 (No changes to standard)	LOAD SHEDDING REMOVED FROM R2, R5, AND R9. OTHERWISE, NO CHANGE FROM PREVIOUSLY BALLOTED VERSION – RESPONSE TEAM BELIEVES NO CHANGES ARE NEEDED TO ADDRESS SOCAL EDISON AND SMA 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.

Modified to address Order No. 693 Directives contained in paragraph 321.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 through July 2, 2010).
4. Initial ballot. (July 2 through July 14, 2010).

Proposed Action Plan and Description of Current Draft:

This is the second draft of the proposed standard. Changes were made to the standard following the first ballot based on stakeholder comments. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	July 20, 2010
2. Conduct recirculation ballot.	July 20–30, 2010
3. Submit standard to BOT for adoption.	August 2010
4. File standard with regulatory authorities.	September 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.

None.

Standard Development Roadmap

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Modified to address Order No. 693 Directives contained in paragraph 321.

Development Steps Completed:

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None.

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.

Modified to address Order No. 693 Directives contained in paragraph 582.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 through July 2, 2010).
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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	July 20, 2010
2. Conduct recirculation ballot.	July 20 – 30, 2010
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Definitions of Terms Used in Standard

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None.

Standard Development Roadmap

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Modified to address Order No. 693 Directives contained in paragraph 582.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
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None.

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Modified to address Order No. 693 Directives contained in paragraph 693.

Development Steps Completed:

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This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

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Modified to address Order No. 693 Directives contained in paragraph 693.

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None.

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.

Modified to address Order No. 693 Directives contained in paragraph 1300.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 through July 2, 2010).
4. Initial ballot. (July 2 through July 14, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	July 20, 2010
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Definitions of Terms Used in Standard

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None.

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.

Modified to address Order No. 693 Directives contained in paragraph 1300.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 through July 2, 2010).
4. Initial ballot. (July 2 through July 14, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	July 20, 2010
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None.

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.

Modified to address Order No. 693 Directives contained in paragraphs 1469.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 through July 2, 2010).
4. Initial ballot. (July 2 through July 14, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. Changes were made to the standard following the first ballot based on stakeholder comments. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	July 20, 2010
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4. File standard with regulatory authorities.	September 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.

None.

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.

Modified to address Order No. 693 Directives contained in paragraphs 1469.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 through~~–~~ July 2, 2010).
4. Initial ballot. (July 2 through July~~–~~ 14, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. Changes were made to the standard following the first ballot based on stakeholder comments. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	July 20, 2010
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Definitions of Terms Used in Standard

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None.

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.

Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 through July 2, 2010).
4. Initial ballot. (July 2 – 14, 2010).

Proposed Action Plan and Description of Current Draft:

This is the second draft of the proposed standard. Changes were made to the standard following the first ballot based on stakeholder comments. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	July 20, 2010
2. Conduct recirculation ballot.	July 20 – 30, 2010
3. Submit standard to BOT for adoption.	August 2010
4. File standard with regulatory authorities.	September 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.

None.

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.

Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 through July 2, 2010).
4. Initial ballot. (July 2 – 14, 2010).

Proposed Action Plan and Description of Current Draft:

This is the second draft of the proposed standard. Changes were made to the standard following the first ballot based on stakeholder comments. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments on initial ballot.	July 20, 2010
2. Conduct recirculation ballot.	July 20 – 30, 2010
3. Submit standard to BOT for adoption.	August 2010
4. File standard with regulatory authorities.	September 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.

None.

Implementation Plan for Standards:

- BAL-002-1 — Disturbance Control Performance;
- EOP-002-3 — Capacity and Energy Emergencies;
- FAC-002-1 — Coordination of Plans For New Generation, Transmission, and End-User Facilities;
- MOD-021-2 — Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts;
- PRC-004-2 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations;
- VAR-001-2 — Voltage and Reactive Control.

Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), approved or in progress, that must be implemented before these standards can be implemented.

New Definitions
None.

Modified Definitions
None.

Retired Definitions
None.

Modified Standards
BAL-002-1 supersedes BAL-002-0.
EOP-002-3 supersedes EOP-002-2.
FAC-002-1 supersedes FAC-002-0.
MOD-021-2 supersedes MOD-021-1.
PRC-004-2 supersedes PRC-004-1.
VAR-001-2 supersedes VAR-001-1.

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Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

	Balancing Authority	Transmission Planner	Transmission Owner	Transmission Operator	Resource Planner	Load-Serving Entity	Planning Authority	Distribution Provider	Reserve Sharing Group	Regional Reliability Organization	Generator Owner	Generator Operator	Purchasing Selling Entity	Reliability Coordinator
BAL-002-1	X								X	X				
EOP-002-3	X					X								X
FAC-002-1		X	X			X	X	X			X			
MOD-021-2		X				X								
PRC-004-2		X	X	X		X					X			
VAR-001-2				X		X							X	

Proposed Effective Dates

For MOD-021-1

The first day of the first calendar quarter after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees' adoption.

For EOP-002-3, FAC-002-1, and VAR-001-2

The first day of the first calendar quarter, six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

For BAL-002-1and PRC-004-2

The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

Implementation Plan for Standards:

- BAL-002-1 — Disturbance Control Performance;

~~BAL-005-1, Automatic Resource Control;~~

~~EOP-001-2, Emergency Operations Planning;~~

- EOP-002-3 — Capacity and Energy Emergencies;

~~EOP-003-2, Load Shedding Plans;~~

~~EOP-004-2, Disturbance Reporting;~~

- FAC-002-1 — Coordination of Plans For New Generation, Transmission, and End-User Facilities;

~~MOD-017-1, Aggregated Actual and Forecast Demands and Net Energy for Load;~~

~~MOD-019-1, Reporting of Interruptible Demands and Direct Control Load Management;~~

~~MOD-020-1, Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators;~~

- MOD-021-2 — Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts;
- PRC-004-2 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations;
- VAR-001-2 — Voltage and Reactive Control.

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), approved or in progress, that must be implemented before these standards can be implemented.

New Definitions

~~Automatic Resource Control (ARC)~~None.

Modified Definitions

~~Automatic Generation Control (AGC)~~
~~Demand-Side Management (DSM)~~
~~Operating Reserve – Spinning~~
~~Operating Reserve – Supplemental~~
~~Regulating Reserve~~None.

Retired Definitions

~~Spinning Reserve~~None.

Modified Standards

BAL-002-1 supersedes BAL-002-0.
~~BAL-005-1 supersedes BAL-005-0.~~
~~EOP-001-2 supersedes EOP-001-1.~~

EOP-002-3 supersedes EOP-002-2.
~~EOP-003-2 supersedes EOP-003-1.~~
~~EOP-004-2 supersedes EOP-004-1.~~
FAC-002-1 supersedes FAC-002-0.
~~MOD-017-1 supersedes MOD-017-0.~~
~~MOD-019-1 supersedes MOD-019-0.~~
~~MOD-020-1 supersedes MOD-020-0.~~
MOD-021-2 supersedes MOD-021-1.
PRC-004-2 supersedes PRC-004-1.
VAR-001-2 supersedes VAR-001-1.

Compliance with Standards

Once the standards become effective, the responsible entities identified in the applicability section of the standards must comply with the requirements. These include:

	Balancing Authority	Transmission Planner	Transmission Owner	Transmission Operator	Resource Planner	Load-Serving Entity	Planning Authority	Distribution Provider	Reserve Sharing Group	Regional Reliability Organization	Generator Owner	Generator Operator	Purchasing Selling Entity	Reliability Coordinator
BAL-002-1	X								X	X				
~~BAL-005-1~~	~~X~~			~~X~~		~~X~~						~~X~~		
~~EOP-001-2~~	~~X~~			~~X~~										
EOP-002-3	X					X								X
~~EOP-003-2~~	~~X~~			~~X~~										
~~EOP-004-2~~	~~X~~			~~X~~		~~X~~		~~X~~		~~X~~		~~X~~		~~X~~
FAC-002-1		X	X			X	X	X			X			
~~MOD-017-1~~		~~X~~			~~X~~	~~X~~	~~X~~							
~~MOD-019-1~~		~~X~~			~~X~~	~~X~~	~~X~~							
~~MOD-020-1~~		~~X~~			~~X~~	~~X~~								
MOD-021-2		X				X								
PRC-004-2		X	X	X		X					X			
VAR-001-2				X		X							X	

Proposed Effective Dates

For MOD-021-1

The first day of the first calendar quarter after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees' adoption.

For ~~BAL-005-1, EOP-001-2,~~ EOP-002-3, ~~EOP-004-2,~~ FAC-002-1, and VAR-001-2

The first day of the first calendar quarter, six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

For BAL-002-1~~, EOP-003-2, MOD-017-1, MOD-019-1, MOD-020-1~~ and PRC-004-2~~,~~

The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

e. Project 2010-12 — Order 693 Directives

Action Required
In accordance with the implementation plans provided therein, approve the following proposed standards, new or modified terms, and associated Violation Risk Factors and Violation Severity Levels, direct staff to file the standards with FERC and applicable governmental authorities in Canada. Concurrently retire existing versions of standards or NERC Glossary terms that are superseded by the approval as requested.

Revised Standards and Associated VRFs and VSLs for Approval

- BAL-002-1 - Disturbance Control Performance
- EOP-002-3 - Capacity and Energy Emergencies
- FAC-002-1 - Coordination of Plans For New Generation, Transmission, and End-User Facilities
- MOD-021-2 - Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts
- PRC-004-2 - Analysis and Mitigation of Transmission and Generation Protection System Misoperations
- VAR-001-2 - Voltage and Reactive Control

Existing Standards to Retire

- BAL-002-0 - Disturbance Control Performance
- EOP-002-2 - Capacity and Energy Emergencies
- FAC-002-0 - Coordination of Plans For New Generation, Transmission, and End-User Facilities
- MOD-021-1 - Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts
- PRC-004-1 - Analysis and Mitigation of Transmission and Generation Protection System Misoperations
- VAR-001-1 - Voltage and Reactive Control

NERC Glossary of Term Additions/Modifications/Retirement

- None.

Effective Dates

- MOD-021-1 - the first day of the first calendar quarter after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees' adoption.
- EOP-002-3, FAC-002-1, and VAR-001-2 - first day of the first calendar quarter, six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

- BAL-002-1 and PRC-004-2 - first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

Background

Following the issuance of the FERC orders on March 18, 2010, NERC increased its focus to addressing outstanding directives from FERC Order 693, issued in March, 2007. The request for approval herein reflects the first phase of a multi-phased activity to address the Order No. 693 directives completely by the end of 2011. The proposal contains 6 revised standards that address 11 directives that were deemed to be non- or less controversial to implement. Concurrent to the implementation of these modifications, NERC proposes to retire 6 existing standards.

The proposed standards are being processed through an expedited standards development process approved by the Standards Committee Executive Committee in June, 2010. The Standards Authorization Request and set of proposed standard changes were drafted by NERC staff, reviewed, and modified by a team of industry experts identified by staff, then presented for Standards Committee approval. After modifying the proposal to assure the changes did not conflict with the work of existing drafting teams that were nearing project completion, the Standards Committee Executive Committee approved the request and the set of proposed changes were posted for concurrent comment and initial ballot that began on June 18 and concluded on July 14, 2010. The ballot was conducted on a directive-level basis, in essence, a line item ballot. Proposals that did not garner sufficient support as demonstrated by the results of the initial ballot and the comments received were withdrawn from consideration in the recirculation ballot. The team was permitted to make modifications between the initial and recirculation ballots based on comments received to improve the overall quality of the standard. The recirculation ballot is slated to occur from July 20-30, 2010. NERC is also conducting a non-binding poll of the proposed VRFs and VSLs concurrent with the standards ballot. The results of the initial and recirculation ballots as well as the summary of the comments received will be provided at the August, 2010 Board meeting.

A link to the project history and files is included here for reference:
at http://www.nerc.com/filez/standards/Project2010-12_Order-693_Directives.html.

While the standards changes are not expected to be controversial, the process used to develop the initial proposal for Standards Committee consideration engendered concern from some industry representatives. Several commenters suggested that NERC staff involvement should not include drafting requirements or selecting experts to support standards development, and that the single concurrent comment and ballot approach was inappropriate. However, these actions are consistent with ANSI essential principles, and any interested party, including NERC staff, can propose a standards change request that includes red-line changes to the standards.

Exhibit C

Response Team roster

693 Directives Response Team

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