

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

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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 Matthey	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 McElhane	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	City of Vero Beach	1	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
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Walt Gill	Lake Worth Utilities	1	Disapprove	

Voter	Entity	Segment	P 321	Comments
Larry E Watt	Lakeland Electric	1	Disapprove	suggested.
Terri Pyle	Oklahoma Municipal Power Authority	4	Disapprove	<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p>
Eric Egge	Black Hills Corp	1	Disapprove	<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p>
Daniel Prowse	Manitoba Hydro	6	Disapprove	Changing "NERC" to "ERO" is not valid in Canadian jurisdictions
Michelle Rheault	Manitoba Hydro	1	Disapprove	Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concerns.
Danny McDaniel	Cleco Power LLC	1	Disapprove	<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concerns.</p>
Bryan Y Harper	Cleco Utility Group	3	Disapprove	
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	<p>Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."</p> <p>Response: Please see response to Doug Hohlbaugh.</p>
Kevin Query	FirstEnergy Solutions	3	Disapprove	
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	<p>comments will be filed via the formal comment form</p> <p>Response: Please see the appropriate Consideration of Comments for response.</p>

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
Guy Andrews	Georgia System Operations Corporation	4	Approve	Response: No response required.
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
				<p>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."</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p> <p>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</p>

Voter	Entity	Segment	P 321	Comments
				<p>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.</p> <p>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.</p>
John Tolo	Tucson Electric Power Co.	1	Disapprove	<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concern.</p>
Lee Schuster	Florida Power Corporation	3	Disapprove	<p>Section 4 Applicability, subsection 4.3 should be changed from Regional Reliability Organization to Regional Entity</p> <p>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.</p>
James Eckelkamp	Progress Energy	6	Disapprove	
Wayne Lewis	Progress Energy Carolinas	5	Disapprove	
Gregg R Griffin	City of Green Cove Springs	3	Disapprove	<p>strike sentence 'this period may be adjusted to better suit the needs of an interconnection based on analysis approved by the NERC OC</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p>
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	<p>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</p>

Voter	Entity	Segment	P 321	Comments
				<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p> <p>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?</p> <p>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.</p>
Gregory Campoli	NYISO	2	Disapprove	<p>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?</p> <p>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.</p>

Voter	Entity	Segment	P 321	Comments
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	<p>The ERO change appears to be fine however this doesn't warrant a modification to the Standard.</p> <p>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.</p> <p>Would it be possible to change RRO to RE throughout all these Tiger standards while we are in there?</p> <p>Response: The Response Team is undertaking this effort as appropriate with regard to the standards being modified as part of this project.</p>
Donald S. Watkins	BPA	1	Disapprove	<p>The ERO should not be determining the DCS period. There is no due process.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, which we believe will address your concern.</p>
Terry L. Blackwell	Santee Cooper	1	Disapprove	<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p>
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Disapprove	<p>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.</p> <p>Response: This project is using a process that has been approved by the Standards Committee.</p> <p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p>

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 Committee ERO." 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. Strike the last sentence, referring 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 impacted 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	Muscantine 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
				<p>change the reference from NERC OC to the ERO in R4.2 and 6.2.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p>
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p>
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p> <p>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.</p>

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	<p>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.</p> <p>Response: The Response Team has deleted the last sentence in R4.2 and R6.2, as suggested.</p>

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 McElhane	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 Query	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 Matthey	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 adds ambiguity. (b) Likewise, the implication that the DSM does not have to be controlled by an operator, means that DSM will not be comparable, 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
				<p>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</p>
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	<p>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</p>

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 inclusionary 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
				<p>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 FERC's 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</p>

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	
Frank Gaffney	Florida Municipal Power Agency	4	Disapprove	
Walt Gill	Lake Worth Utilities	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.
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 definition 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-efficient 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 - 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 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
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
				<p>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.</p>
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	<p>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.</p>
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	<p>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”.</p>
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	

Voter	Entity	Segment	P 330	Comments
				<p>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.</p>
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	<p>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</p>

Voter	Entity	Segment	P 330	Comments
				<p>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.</p>
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	<p>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.</p>

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	Dynergy Inc.	5	Abstain	

² The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.
July 20, 2010

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 Query	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 Matthey	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/drtdf/DADS_Phase_I&II_Final_050510.pdf Under 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 unreliable to be considered 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 inappropriate. The definition of DSM, or any definition for that matter, should not refer to "violating 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 prouduct 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
				<p>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.</p>
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	<p>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?</p>
James R. Keller	Wisconsin Electric Power Marketing	3	Disapprove	
Anthony Jankowski	Wisconsin Energy Corp.	4	Disapprove	
Michael F Gildea	Dominion Resources Services	3	Approve	<p>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</p>
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
				<p>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.</p>

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 Saxena	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 McElhane	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 Query	FirstEnergy Solutions	3	Disapprove	
Mark S Travagianti	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 Matthey	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 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. 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/drdf/DADS_Phase_I&II_Final_050510.pdf Under 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 may 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	
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 service 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 product capable of assuming this role.
Larry Akens	Tennessee Valley Authority	1	Disapprove	

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 "violating 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
				<p>“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.</p>
Guy Andrews	Georgia System Operations Corporation	4	Disapprove	<p>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:</p>
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	<p>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</p>
Harold Taylor, II	GTC	1	Disapprove	<p>“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</p>

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
				<p>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.</p>

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	Dynergy 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 Matthey	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 schedule 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 to software and telemetry. Controlling load would/does require different software and 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 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.
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" Demand Side Management Resource should be defined and replace DSM in the revised definition of Regulating Reserve; DSM is an activity and program, not a MW resource. Also, we believe that ARC is an acronym 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 Commission's 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 respond 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
				<p>definition 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 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.</p>
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	<p>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.</p>
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
				<p>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."</p>
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Disapprove	<p>The term "AGC" is used through 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 other 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.</p>
Kim Warren	IESO	2	Approve	<p>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</p>

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 Travagianti	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 Matthey	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	<ul style="list-style-type: none"> 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 requirement 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 standard 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	
Willet (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 Query	FirstEnergy Solutions	3	Disapprove	
Mark S Travagianti	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 Matthey	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 occurrence. 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	<p>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, we 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:</p> <ul style="list-style-type: none"> 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 Florum	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 the requirement excessively prescriptive. 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 Query	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 Matthey	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 Florum	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 Query	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 Matthey	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 additional 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 schedullem 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 tottransmission 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 the requirement excessively prescriptive. 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 Florum	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 Query	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 Matthey	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 BACS DT. 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 Query	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 McElhane	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 Matthey	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	
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" and "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 Query	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 Matthey	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	
Willet (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 Query	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 Matthey	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 McElhane	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 dealt 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) Attachment 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 believes 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 "and those whose mitigation plans are hindered by a lack of transmission capability". 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 generation capacity emergency can be caused by lack of transmission capability, dictating a response via an operational standard is not going to get 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 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 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	
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	
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
				<p>“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.</p>
John K Loftis	Dominion Virginia Power	1	Approve	<p>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.”</p>
Mike Garton	Dominion Resources, Inc.	5	Approve	<p>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.”</p>
Daniel Prowse	Manitoba Hydro	6	Disapprove	<p>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”</p>
Michelle Rheault	Manitoba Hydro	1	Disapprove	<p>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”</p>

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 Matthey	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 Query	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 McElhanev	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 to explain 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.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Approve	Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.
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 from 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 Matthey	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 Query	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 Florum	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-requirements 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 “appropriate.” 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				<p>actions as appropriate to the current situation based on operator discretion to reduce risksto..."If this is changed, then M2 needs to change to reflect any changes.</p> <p>Response: The original language form the requirement, "when required and as appropriate," is intended to ensure entities take the appropriate action that is required.</p>
Gwen S Frazier	Gulf Power Co.	3	Disapprove	
Don Horsley	Mississippi Power	3	Disapprove	
Linda R. Jacobson	City of Farmington	3	Approve	<p>R4 includes the phrase "and if appropriate." Who or what determines what is or isn't appropriate?</p> <p>Response: This language was not modified from the original standard, only moved to make the requirement more easily understood.</p>
Charles H Yeung	Southwest Power Pool	2	Disapprove	<p>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 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?</p> <p>Response: This language was not modified from the original standard.</p>
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	<p>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</p>

Voter	Entity	Segment	P 582	Comments
				<p>supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)”</p> <p>Response: The directive to address the stated ISONE concern indicates that the answer was not obvious; hence the modification.</p> <p>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.</p>
Robert Martinko	FirstEnergy Energy Delivery	1	Approve	<p>The changes to R2 largely seem unnecessary, however, FE approves based on the change does not seem to harm reliability or reduce clarity.</p>
Douglas Hohlbaugh	Ohio Edison Co.	4	Approve	<p>Response: Thank you for your supporting comment.</p>
Ajay Garg	Hydro One Networks, Inc.	1	Disapprove	<p>The ISO-NE comment to the NOPR was valid for a prior version of the standards. It is no longer necessary.</p>
Michael D. Penstone	Hydro One Networks, Inc.	3	Disapprove	<p>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.</p>
Gregory Campoli	NYISO	2	Disapprove	<p>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</p>

Voter	Entity	Segment	P 582	Comments
				<p>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.”</p> <p>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.</p> <p>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.</p>
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	<p>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</p>

Voter	Entity	Segment	P 582	Comments
				<p>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.”</p> <p>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.</p> <p>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.</p>
Kathleen Goodman	ISO New England, Inc.	2	Abstain	<p>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.</p> <p>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.</p>

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.
Guy Andrews	Georgia System Operations Corporation	4	Approve	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	
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.
Stanley M Jaskot	Entergy Corporation	5	Disapprove	Response: The Response Team believes these comments are related to Paragraph 573, and will consider them when evaluating the changes related to that paragraph.

Voter	Entity	Segment	P 582	Comments
John Tolo	Tucson Electric Power Co.	1	Approve	<p>R4 includes the phrase “and if appropriate.” Who or what determines what is or isn’t appropriate?</p> <p>Response: This language was not modified from the original standard, only moved to make the requirement more easily understood.</p>

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 Matthey	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 McElhane	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 Travagianti	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 wouldn'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 Florum	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 DLCM 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 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.
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 McElhaneey	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 Matthey	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 to immediately implemented all but one (1) of the 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 to immediately 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
				not immediately implement any remedies. 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	
Willet (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 Travagianti	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 Matthey	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 vague.
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 inappropriate 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 Project 2007-01 contains requirements related to underfrequency load shedding, contains modifications to revise EOP-003, and is in the pre-ballot review period for the third draft and is therefore superior to the version proposed by this SDT and is further along in the 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. DePorter	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 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.
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	R3 should specify it is manual load shedding or operator initiated load shedding, 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 tabletop, 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 of load shedding - automatic or manual. R1 is clearly Automatic and APPA and ISONE 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.
Anthony L Wilson	Georgia Power Co.	3	Disapprove	Requirement R3 does not clarify the current ambiguity about what type of load shedding - automatic or manual. R1 is clearly Automatic and APPA and ISONE 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.
Gwen S Frazier	Gulf Power Co.	3	Disapprove	Requirement R3 does not clarify the current ambiguity about what type of load shedding - automatic or manual. R1 is clearly Automatic and APPA and ISONE 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.
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. <ul style="list-style-type: none"> 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 Florum	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
				<p>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.</p>
Alan Gale	City of Tallahassee	5	Disapprove	<p>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?</p>
Raj Rana	AEP	3	Disapprove	<p>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.</p>
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 Travagianti	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 Matthey	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 McElhane	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 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 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	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.
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 inappropriate 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 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

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	<ul style="list-style-type: none"> 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	<p>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.</p>

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 simulate load shed 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: "At 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 emergency 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 vague.
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

Voter	Entity	Segment	P 603	Comments
				<p>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)</p>
Walt Gill	Lake Worth Utilities	1	Disapprove	<p>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)</p>
Larry E Watt	Lakeland Electric	1	Disapprove	<p>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)</p>
Carolyn Ingersoll	Constellation Energy	3	Disapprove	<p>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."</p>
Gregory Campoli	NYISO	2	Disapprove	<p>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</p>

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 shedding. ATC 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 extent 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 Matthey	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 McElhane	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. Furthermore, 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 Question # 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 Matthey	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 Travagianti	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 McElhane	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 vague. Drafting team should describe what is expected. (b) R3.1 - "analyze performance of their equipment" is vague. 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 requested 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 believes 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 loses 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, constitute 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 facilities 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 limitations 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 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.
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 Florum	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 Query	FirstEnergy Solutions	3	Opposed	

Voter	Entity	Segment	P 612 VRF and VSLs	Comments
Mark S Travagianti	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 Matthey	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 McElhane	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 entities 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 lose 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, constitute 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, therefore 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	
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 analyzed: 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 Query	FirstEnergy Solutions	3	Approve	
Mark S Travagianti	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 Florum	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 Matthey	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 McElhane	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	<p>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.</p> <p>2. These new provisions are in potential conflict with the Disturbance/Sabotage Reporting Standard Drafting Team, and should be addressed by that team.</p> <p>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.</p> <p>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?</p>
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 part 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	
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 responsive 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				<p>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.</p>

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	
Nickasha 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 Query	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 Florum	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 McElhane	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 Matthey	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	<p>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.</p> <p><i>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.</i></p>
Michael T. Quinn	Oncor Electric Delivery	1	Disapprove	<p>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.</p> <p><i>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.</i></p>
Charles H Yeung	Southwest Power Pool	2	Disapprove	<p>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.</p> <p><i>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.</i></p>
David A. Lapinski	Consumers Energy	3	Disapprove	<p>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.</p> <p><i>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.</i></p>

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. <i>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.</i>
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 contingency studies. I do agree that this analysis must be performed 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 says we must provide evidence of assessment of the reliability impact, but we do not have this information, our transmission providers retain it. <i>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.</i>
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 makes this seemingly trivial request more complex than the requestor makes it out to be. 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. <i>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.</i>
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 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.” <i>Response: We do not believe the use of this phrase causes any problems, and none have been</i>
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	<p>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?</p> <p>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.</p>
Greg C Parent	Manitoba Hydro	3	Disapprove	
Michelle Rheault	Manitoba Hydro	1	Disapprove	
Martin Bauer P.E.	U.S. Bureau of Reclamation	5	Disapprove	<p>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 contingency conditions. This is normally performed by the TP.</p> <p>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.</p>
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	<p>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.</p> <p>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.</p>
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
				<p>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.”</p> <p>Response: We do not believe the use of this phrase causes any problems, and none have been specifically identified in the comment.</p>
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	<p>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.</p> <p>Response: We do not believe the use of this phrase causes any problems, and none have been specifically identified in the comment.</p>
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	<p>Why not replace RRO with RE throughout?, otherwise this looks reasonable with regard to the order.</p> <p>Response: Only those standards associated with Directives were included in this effort; accordingly, there have only been changes in these standards.</p>

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 Florum	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 Query	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 Matthey	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 explicitly 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

Voter	Entity	Segment	P 1249	Comments
				appropriately.
Louis S Slade	Dominion Resources, Inc.	6	Disapprove	<p>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 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.4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p>
Mike Garton	Dominion Resources, Inc.	5	Disapprove	
John K Loftis	Dominion Virginia Power	1	Disapprove	
George R. Bartlett	Entergy Corporation	1	Disapprove	<p>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</p>
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 requirements 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	<p>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.</p> <p>Pursuant to the NERC Functional Model, the Transmission Planner performs the following:</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary 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.</p> <p>R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p>
Larry Akens	Tennessee Valley	1	Disapprove	The addition 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 section 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 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 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 stations may be used in forecasts and different stations may be used in summer versus winter, given variations 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 Florum	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 Travagianti	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 Matthey	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	<p>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.</p>
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	
Willet (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 Florum	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 Matthey	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 explicitly 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	<p>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)”.</p>
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	<p>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.</p>
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	<p>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 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.4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p>
George R. Bartlett	Entergy Corporation	1	Disapprove	<p>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</p>
Stanley M Jaskot	Entergy Corporation	5	Disapprove	<p>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</p>

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 requirements 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	
George T. Ballew	Tennessee Valley Authority	5	Disapprove	The additon of Transmsion 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 shoild 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	<p>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.</p> <p>Pursuant to the NERC Functional Model, the Transmission Planner performs the following:</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary 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.</p> <p>R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p>
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.			<p>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.</p>
Charles H Yeung	Southwest Power Pool	2	Disapprove	<p>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</p>

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 Matthey	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.			<p>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.</p>
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 Query	FirstEnergy Solutions	3	Disapprove	
Mark S Travagianti	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 Matthey	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 explicitly 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 forecasting 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 do 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
				<p>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.</p>
George R. Bartlett	Energy Corporation	1	Disapprove	<p>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</p>
Stanley M Jaskot	Energy Corporation	5	Disapprove	<p>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</p>

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 forecast 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 a standards 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 Florum	LES	5	Disapprove	
Eric Ruskamp	LES	6	Disapprove	
Larry Akens	Tennessee Valley Authority	1	Disapprove	The addition of Transmission Planner does not improve or enhance reliability. Facility owners (Transmission Owner and Distribution Provider and possible 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. 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
				<p>Pursuant to the NERC Functional Model, the Transmission Planner performs the following:</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary 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.</p> <p>R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p>
Bob Essex	Cowlitz County PUD	5	Disapprove	<p>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.</p> <p>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.</p>
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 getting 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 randomly, 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 Query	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 Matthey	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 Matthey	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 McElhane	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	<p>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.</p>
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	<p>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</p>

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 explicitly 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	
Willet (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 Florum	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
				<p>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.</p>
George R. Bartlett	Entergy Corporation	1	Disapprove	<p>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</p>
Stanley M Jaskot	Entergy Corporation	5	Disapprove	<p>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</p>

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	
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.

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 addition 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 section 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
				<p>section 4: Applicability.</p> <p>Pursuant to the NERC Functional Model, the Transmission Planner performs the following:</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary 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.</p> <p>R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p>
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	<p>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.</p>
Michelle Rheault	Manitoba Hydro	1	Disapprove	<p>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</p>

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 applicable 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 inaccuracies 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 penalize 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 forecast down by 15% (to be more accurate) and the economy recovers? We will be missing 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 randomly, which appears to be messy. More importantly, regarding the FERC directive, it 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 its 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 Matthey	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	<p>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.</p>
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 Travagianti	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 Florum	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 Matthey	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	<p>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.</p>
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	<p>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</p>

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 explicitly 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
				<p>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 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.4. R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p>
George R. Bartlett	Entergy Corporation	1	Disapprove	<p>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</p>
Stanley M Jaskot	Entergy Corporation	5	Disapprove	<p>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</p>

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 addition 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 section 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	<p>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.</p> <p>Pursuant to the NERC Functional Model, the Transmission Planner performs the following:</p> <p>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.</p> <p>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</p>

Voter	Entity	Segment	P 1255	Comments
				<p>temperature and humidity data for the prior year upon request of the Planning Authority, Resource Planner and/or Transmission Planner.</p> <p>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.</p> <p>R2, as written, would decrease reliability by allowing a wider bandwidth before action is necessary 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.</p> <p>R1.5 is not clear, as written, and we suggest that it should be given to a standards drafting team to develop appropriately.</p>
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	<p>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</p>

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	
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 its 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 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.
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 Matthey	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 Query	FirstEnergy Solutions	3	Disapprove	
Mark S Travagianti	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 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
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
Willet (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 similar hour where DCLM is not implemented to calculate the actual amount 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 Travagianti	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	<p>“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</p>
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 assumptions 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 Flrom	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 similar hour where DCLM is not implemented to calculate the actual amount 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 DCLM 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 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.
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 its 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 Matthey	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 McElhaneey	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 similar hour where DCLM is not implemented to calculate the actual amount 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	
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 Matthey	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 or 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 al 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 Travagianti	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 Florum	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
				<p>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.</p>
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	<p>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.</p>

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 that 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 that 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 that 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 that 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 similar hour where DCLM is not implemented to calculate the actual amount and extrapolate the value to peak load..
Raj Rana	American Electric Power	3	Disapprove	R2.1 "...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 forecasts 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
Nickasha 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 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 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 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 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 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 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 given instant 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 Query	FirstEnergy Solutions	3	In Favor	
Mark S Travagianti	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 Florum	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 Matthey	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 McElhane	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 that did not have 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 similar hour where DCLM is not implemented to calculate the actual amount 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 Matthey	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
Willet (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 Travagianti	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 Florum	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	<p>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.</p> <p>Response: Thank you for your supportive comment.</p>
Joseph O'Brien	Northern Indiana Public Service Co.	6	Approve	<p>seems reasonable</p> <p>Response: Thank you for your supportive comment.</p>
Jason L Marshall	Midwest ISO, Inc.	2	Approve	<p>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.</p> <p>Response: Thank you for your supportive comment.</p> <p>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.</p>
Jeffrey Mueller	Public Service Electric and Gas Co.	3	Approve	<p>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.</p> <p>Response: Thank you for your supportive comment.</p>
James D. Hebson	PSEG Energy Resources & Trade LLC	6	Approve	<p>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.</p> <p>Response: Thank you for your supportive comment.</p>
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 McElhane	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.
Bryan Y Harper	Cleco Utility Group	3	Disapprove	Response: The Response Team believes the word "Controllable" is redundant. Specific attributes of DSM will need to be addressed through further work.
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 applicable 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, 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	
Willet (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	<p>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.</p> <p>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.</p>
Kevin Koloini	American Municipal Power - Ohio	4	Approve	<p>Please consider removing LSE from the applicability to reduce unnecessary "not applicable" filings.</p> <p>Response: The Response Team has removed the Load Serving Entity from the standard as suggested.</p>
Bob Essex	Cowlitz County PUD	5	Approve	<p>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.</p> <p>Response: The Response Team has corrected the reference to “RRO” as suggested. Additionally, the</p>
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 phrase "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			<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.</p>
Rebecca Berdahl	Bonneville Power Administration	3	Approve	
Jerome Murray	Oregon Public Utility Commission	9	Approve	<p>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 phrase "according to the Regional Entity's procedures."</p> <p>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.</p>
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	<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.</p>
Hao Li	Seattle City Light	4	Approve	
Pawel Krupa	Seattle City Light	1	Approve	
John Tolo	Tucson Electric Power Co.	1	Approve	<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.</p>

Voter	Entity	Segment	P 1469	Comments
Louise McCarren	Western Electricity Coordinating Council	10	Approve	<p>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."</p> <p>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.</p>
Randall McCamish	City of Vero Beach	1	Approve	<p>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?</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.</p>
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	<p>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.</p> <p>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.</p>
Daniel Mark Bedbury	Eugene Water & Electric Board	6	Approve	<p>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</p>

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 Query	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 Matthey	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	<p>(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.</p> <p>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.</p> <p>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.</p> <p>The Response Team has removed the Load Serving Entity and Transmission Operator as suggested.</p>
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
				<p>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</p>

Voter	Entity	Segment	P 1469	Comments
				<p>Compliance Information section should be revised to read "... the Generator Owner that owns a generator Protection System or a transmission Protection System shall demonstrate..."</p> <p>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.</p>
David H. Boguslawski	Northeast Utilities	1	Disapprove	<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator in response to the suggestions of other commenters.</p> <p>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.</p> <p>R2 has been modified as suggested.</p>
Brian Evans-Mongeon	Utility Services, Inc.	8	Disapprove	<p>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.</p> <p>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.</p>
James V. Petrella	Atlantic City Electric Co.	3	Disapprove	<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator, as well as the joint ownership language, as suggested.</p>
Kenneth Dresner	FirstEnergy Solutions	5	Disapprove	<p>Comments to each question are the same as those submitted by Doug Hohlbaugh, Ohio Edison Co., Segment 4. Please refer to Doug's comments."</p> <p>Response: Please see responses to Doug Hohlbaugh.</p>

Voter	Entity	Segment	P 1469	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 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 Florum	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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				<p>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..."</p> <p>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.</p>
Brock Ondayko	AEP Service Corp.	5	Disapprove	<p>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</p>

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				<p>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..."</p> <p>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.</p>

Voter	Entity	Segment	P 1469	Comments
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	<p>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.</p> <p>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.</p>
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	<p>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</p>

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				<p>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.</p> <p>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.</p>
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
Bryan Y Harper	Cleco Utility Group	3	Disapprove	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.
Steve Alexanderson	Central Lincoln PUD	3	Disapprove	<p>It remains unclear how an entity can comply with any of the requirements in the absence of a Regional Entity procedure.</p> <p>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.</p>
David A. Lapinski	Consumers Energy	3	Disapprove	<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator from</p>
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	<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity from the standard as suggested, as well as the language referring to joint ownership.</p>
George R. Bartlett	Entergy Corporation	1	Disapprove	<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator from the standard as suggested.</p>
Stanley M Jaskot	Entergy Corporation	5	Disapprove	
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	<p>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</p>

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				<p>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.</p> <p>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.</p>
Richard J Kafka	Potomac Electric Power Co.	1	Disapprove	<p>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.</p> <p>Response: The Response Team has removed the language related to joint ownership as suggested.</p>
John Canavan	NorthWestern Energy	1	Disapprove	<p>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 analysis/reporting occurs for all transmission/generation that the entity has ownership in</p> <p>Response: The Response Team has removed the language related to joint ownership in response to the suggestions of other commenters.</p>
Mark Ringhausen	Old Dominion Electric Coop.	4	Disapprove	<p>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 Analysis 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.</p> <p>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.</p>
Linda Horn	Wisconsin Electric Power Co.	5	Disapprove	<p>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</p>

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: <ul style="list-style-type: none"> 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
				<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator, and restored the deleted language regarding DP applicability.</p>
Amir Y Hammad	Constellation Power Source Generation, Inc.	5	Disapprove	<p>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.</p> <p>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.</p>
Marjorie Parsons	Tennessee Valley Authority	6	Disapprove	<p>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</p>

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 should 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.
Larry Akens	Tennessee Valley Authority	1	Disapprove	Response: The Response Team has removed the Load Serving Entity and Transmission Operator as suggested.
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 secure 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
				<p>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.</p> <p>Response: The Response Team has removed the Load Serving Entity and Transmission Operator as suggested.</p>
Richard J. Mandes	Alabama Power Co.	3	Disapprove	<p>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...”)</p> <p>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.”)</p> <p>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.</p> <p>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 agree that 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</p>
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
				<p>developed to address to the Functional Model.</p> <p>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.</p>
William D Shultz	Southern Co. Generation	5	Disapprove	<p>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 ...")</p> <p>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.</p>
Horace Stephen Williamson	Southern Co. Services, Inc.	1	Disapprove	<p>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</p>

Voter	Entity	Segment	P 1469	Comments
				<p>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.</p> <p>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.</p>

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	
Willet (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 Florum	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	<p>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. .</p> <p>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.</p>
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	<p>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.</p> <p>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.</p>
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 Matthey	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 McElhane	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	<p>(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?</p> <p>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.</p> <p>Regarding item B, while the proposed language has merit, we do not believe it to be associated with any directive.</p>
Edward P. Cox	AEP Marketing	6	Disapprove	<p>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.</p> <p>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.</p> <p>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.</p>
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	<p>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.</p> <p>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.</p>
Michael T. Quinn	Oncor Electric Delivery	1	Disapprove	<p>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.</p> <p>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).</p>
David H. Boguslawski	Northeast Utilities	1	Disapprove	<p>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.</p> <p>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.</p>
David A. Lapinski	Consumers Energy	3	Disapprove	<p>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.</p> <p>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.</p>
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 agreements 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	<p>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.</p> <p>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.</p>
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	<p>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.</p> <p>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.</p> <p>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.</p>
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	<p>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.</p> <p>Response: The Response Team believes that acquiring appropriate Ancillary Services would qualify as arranging for reactive resources through purchase.</p>
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	<p>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.</p> <p>Response: R5 is included in the existing standard, and only limited changes have been proposed as</p>

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 Query	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	<p>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.</p> <p>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.</p> <p>The Response Team has removed reference to load shedding from R2, R5, and R9.</p>
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	
Mark Peters	Ameren Services	3	Disapprove	<p>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).</p> <p>Response: Thank you for your supportive comment.</p>
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 Matthey	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	<p>(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?</p> <p>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.</p>
George R. Bartlett	Entergy Corporation	1	Disapprove	<p>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.</p> <p>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.</p> <p>The Response Team has removed reference to load shedding from R2, R5, and R9.</p>
Stanley M Jaskot	Entergy Corporation	5	Disapprove	
Mark Ringhausen	Old Dominion Electric Coop.	4	Disapprove	<p>Agree with SoCal that a blanket allowance of reduce reactive support because of DSM must not be assumed.</p> <p>Response: The Response Team agrees that a blanket allowance of reduced reactive support because of DSM must not be assumed.</p>
Carolyn Ingersoll	Constellation Energy	3	Disapprove	<p>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.</p> <p>Response: The Response Team has removed reference to load shedding from R2, R5, and R9.</p>
Charles A. Freibert	Louisville Gas and Electric Co.	3	Disapprove	<p>comments will be filed via the formal comment form</p> <p>Response: Please see the Consideration of Comments for responses.</p>
Jonathan Appelbaum	United Illuminating Co.	1	Disapprove	<p>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.</p>

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; transmsion 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 violate TPL-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	<p>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.</p> <p>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.</p> <p>The Response Team has removed reference to load shedding from R2, R5, and R9.</p>
David A. Lapinski	Consumers Energy	3	Disapprove	<p>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.</p> <p>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.</p>
David Frank Ronk	Consumers Energy	4	Disapprove	
James B Lewis	Consumers Energy	5	Disapprove	
Douglas E. Hils	Duke Energy Carolina	1	Disapprove	<p>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</p>

Voter	Entity	Segment	P 1879	Comments
				<p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p>
Terry L. Blackwell	Santee Cooper	1	Disapprove	<p>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 dashes.</p> <p>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.</p>

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				<p>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.</p> <p>The Response Team has removed reference to load shedding from R2, R5, and R9.</p>
Charles Locke	Kansas City Power & Light Co.	3	Disapprove	<p>Recommended changes to the proposed requirements prevent supporting the VSL proposed changes.</p> <p>Response: The Response Team needs additional explanation to understand the comment.</p>
Michael Gammon	Kansas City Power & Light Co.	1	Disapprove	
Jeff Nelson	Springfield Utility Board	3	Disapprove	<p>See SUB's comment form</p> <p>Response: Please see the appropriate "Consideration of Comments" for response.</p>
Kevin Koloini	American Municipal Power - Ohio	4	Disapprove	<p>Significant variability exists in transmission service agreements 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.</p> <p>Response: The Response Team needs additional explanation to understand the comment.</p>
Tom Bowe	PJM Interconnection, L.L.C.	2	Disapprove	<p>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.</p> <p>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.</p>
Thomas E Washburn	FMPP	6	Disapprove	<p>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.</p> <p>Response: The Response Team has removed reference to load shedding from R2, R5, and R9.</p>
Guy Andrews	Georgia System	4	Disapprove	<p>We disagree with the inclusion of load shedding as a resource in VAR-001 R2, R5, and R9. Controllable</p>

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	Operations Corporation			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.
R Scott S. Barfield-McGinnis	Georgia System Operations Corporation	3	Disapprove	
Harold Taylor, II	GTC	1	Disapprove	
Kathleen Goodman	ISO New England, Inc.	2	Disapprove	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.
Joseph O'Brien	Northern Indiana Public Service Co.	6	Disapprove	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.
Jason L Marshall	Midwest ISO, Inc.	2	Disapprove	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.

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				As such, the Response Team believes it clarifies the standard without precluding the use of other options.