Comment Report

Project Name:	2017-01 Modifications to BAL-003 Phase II | Draft 1
Comment Period Start Date:	7/25/2022
Comment Period End Date:	9/7/2022
Associated Ballots:	2017-01 Modifications to BAL-003 Phase II BAL-003-3 IN 1 ST 2017-01 Modifications to BAL-003 Phase II Implementation Plan IN 1 OT

There were 71 sets of responses, including comments from approximately 187 different people from approximately 118 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Concerns related to the current performance metric for Balancing Authorities, where the median performance of all Operating Year selected events is used to determine compliance, potentially allows for an entity to perform well in the first half of the year and then "detune" their performance for the second half of the year. Discussions related to the current requirement (Requirement R1) concluded that the after-the-fact methodology, with a median performance metric, is the preferred method to measure performance.

To address the concern of Balancing Authorities only performing for a partial year, the Standards Drafting Team (SDT) is proposing a requirement similar to BAL-002-3, Requirement R2. This new requirement in proposed BAL-003-3 (Requirement R5), would mandate that an entity must have an Operating Process as part of its Operating Plan to address the needed Frequency Responsive reserves. Do you agree that the revised language in proposed Requirement R5 addresses the concerns related to the current performance metric for Balancing Authorities? Please provide the reasoning or justification for your position in the comments.

2. To address the concern that the Balancing Authorities are not seeing the FR expected, the drafting team has proposed Requirements R6 and R7. Requirement R6 is modeled after the VAR-002-4.1, Requirement R1 and requires the Generator Operator to operate generators with the Governor in service unless the Balancing Authority has been notified that the Governor is out-of-service. Do you support adding proposed Requirement R6 to BAL-003? Please provide the reasoning or justification for your position in the comments.

3. To address the concern that the Balancing Authorities are not seeing the FR expected, the drafting team has proposed Requirements R6 and R7. Requirement R7 states that the Generator Owner is responsible to ensure minimum settings for the Governor droop and deadband or notification to the Balancing Authority if the settings are not within these minimum settings. Do you support adding proposed Requirement R7 to BAL-003? Please provide the reasoning or justification for your position in the comments.

4. The SDT has made modifications to the standard to allow the data collection process currently performed through the use of the FRS Form 1 to move to a Section 1600 Data Collection process. This would allow the Balancing Authorities to use their own forms to calculate their performance under Requirement R1 while allowing for the needed data collection through a separate means. Do you agree with this modification to the standard? Please provide the reasoning or justification for your position in the comments.

5. Do you believe that proposed Reliability Standard BAL-003-3 can be met in a cost-effective manner? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification. Please provide the reasoning or justification for your position in the comments.

6. Do you have any comments on the modified Violation Severity Level (VSL) for Requirement R1, or for the Violation Risk Factors/VSLs for proposed Requirements R5, R6, and R7?

7. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

8. Please provide any other comments or feedback, which you haven't already provided, to the SDT related to the proposed modifications to the standard.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
Santee Cooper	Chris Wagner	1		Santee Cooper	Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Diana Scott	Santee Cooper	1,3,5,6	SERC
					Adam Taylor	Santee Cooper	1,3,5,6	SERC
					Clarke McKenzie	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Portland General Electric Co.	Daniel Mason	6		Portland General Electric Co.	Brooke Jockin	Portland General Electric Co.	1	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC
					Ryan Olson	Portland General Electric Co.	5	WECC

					Daniel Mason	Portland General Electric Co	6	WECC
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Elizabeth Davis	Elizabeth Davis		RF,SERC	ISO/RTO Council (IRC) Standards Review Committee (SRC)	Mike Del Viscio	PJM	2	RF
					Becky Davis	PJM	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					John Pearson	ISO New England, Inc.	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
					Ali Miremadi	California ISO	2	WECC
James Mearns	James Mearns			NCPA HQ	Jeremy Lawson	Northern California Power Agency	5	WECC
					Marty Hostler	Northern California Power Agency	4	WECC
					Dennis Sismaet	Northern California Power Agency	6	WECC
					Michael Whitney	Northern California Power Agency	3	WECC

Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO

					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
LaKenya VanNorman	LaKenya VanNorman		SERC	Florida Municipal Power Agency (FMPA)	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Public Utility District No. 1 of Chelan County	Meaghan Connell	5		PUD No. 1 of Chelan County	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
					Meaghan Connell	Public Utility District No. 1 Chelan County	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Frazier	1,3,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					James Howell	Southern Company - Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC

					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated	6	NPCC

						Edison Co. of New York		
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion	5	NA - Not Applicable

						Resources, Inc.		
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD / BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Concerns related to the current performance metric for Balancing Authorities, where the median performance of all Operating Year selected events is used to determine compliance, potentially allows for an entity to perform well in the first half of the year and then "detune" their performance for the second half of the year. Discussions related to the current requirement (Requirement R1) concluded that the after-the-fact methodology, with a median performance metric, is the preferred method to measure performance.

To address the concern of Balancing Authorities only performing for a partial year, the Standards Drafting Team (SDT) is proposing a requirement similar to BAL-002-3, Requirement R2. This new requirement in proposed BAL-003-3 (Requirement R5), would mandate that an entity must have an Operating Process as part of its Operating Plan to address the needed Frequency Responsive reserves. Do you agree that the revised language in proposed Requirement R5 addresses the concerns related to the current performance metric for Balancing Authorities? Please provide the reasoning or justification for your position in the comments.

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Does R5 require that BAs know what their available Frequency Response is at all times? The measurement mechanism allows for at least occasional misses on FRM. If BAs are not required to know their available Frequency Response at all times, what is the acceptable interval of study, part of the day ahead plan? Is it expected that the process revise the available FR to show modification post contingency events?	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
The SDT has removed some of the clarity which previously existed for R1. Notwithstanding the text of 4.1, the inclusion of "Responsible Entity" in R1 could be interpreted as unintentionally applying to entities beyond those intended by the SDT. R1 could benefit from additional clarity making it clear that the BA shares no responsibility with other Functional entities, such as the Generator Owner. It may be advisable for the SDT to review BAL-001-TRE-2 and see how applicability was established there, as that standard clearly conveys where responsibilities lie.	
Likes 0	
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

The requirement, as is, is too vague. It states that we would need an operating process to ensure that we should have frequency response at least equal to our FRO. It also indicates that it applies to the Operations Planning time horizon. There is no mention of real-time so it seems like this may be part of the day ahead process. The requirement doesn't indicate the time horizon for which we need to ensure Frequency Response (FR) > FRO. Operations Planning can be 1 day to 1 year out. Does our process need to cover that entire time horizon?

It is vague on what our process should be. Do we have to ensure that FR > FRO for each hour in the day ahead plan? Or do we just need to show that on average FRM > FRO for the day? Does the process have to be hourly, or can it be every 4 hours, or 24 hours? It is not specifying a timeframe other than operations planning time horizon.

What if in real time FR < FRO? There is no mention to real-time so I assume that this would be ok. It is not clear whether we would have to commit additional generation in real-time to ensure FR > FRO. What if a generator trips in real-time? Do you have to commit additional generation to ensure FR > FRO or is it ok as this requirement should only apply to operations planning time horizon?

Another issue we have is that it is very difficult to determine how much frequency response you are going to get from a certain dispatch. Do you simply look at the frequency response settings of a unit? What if the unit is at max; does the dispatch need considered for each hour ensuring there is room? They really don't give much for details on how to determine the expected frequency response of your system. It will depend on the units online, the loads online, types of loads, dispatch on units, DER, etc… There are a lot of factors that need considered in determining the actual frequency response you could expect.

In summary:

- The time horizon could be made more clear. It says operations planning time horizon but at what interval do you need to ensure FR > FRO? Also, is it just day-ahead or also week ahead? Any impacts to real-time operations if things change; which they often do?
- How often do you need to show Frequency Response > FRO?
- What if in real-time Frequency Response < FRO? Do you have to commit additional generation?
- What needs considered in ensuring Frequency Response > FRO? Is it simply using droop and dead-bands of units dispatched and ensuring there is room from where they are dispatched. How do you account for frequency responsive load and also for DER behind the meter that you may not be monitoring?

Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

R5 is a requirement to develop an Operating Process as part if its Operating Plan to address needed Frequency Responsive Reserve. This does not change the performance requirement in R1 in any way. An entity must still meet R1, and to do that, any necessary planning and operation of the resources must be done. There is no performance measure for this requirement, and it appears to an administrative requirement.

Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
R5 is a requirement to develop an Operating Process as part if its Operating Plan to address needed Frequency Responsive Reserve. This does not change the performance requirement in R1 in any way. An entity must still meet R1, and to do that, any necessary planning and operation of the resources must be done. There is no performance measure for this requirement, and it appears to an administrative requirement.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation asserts that “a document that identifies general steps for achieving a generic operating goal” does not alleviate the stated concerns related to the performance metric or eliminate the potential to normalize performance over the course of the year to achieve an annual goal. Further, Reclamation recommends that a reliability standard is not the appropriate form to regulate individual entity performance. Without additional specificity, the requirement to have an Operating Process as part of an Operating Plan is an administrative burden that does not directly improve BES reliability.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy agrees with MISO’s submitted comments for question 1.	

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
This new requirement seems to be more administrative driven rather than performance driven. The Operating plan is to have preparations to maintain the BA FRO and document and demonstrate that it did that. Well, the question is what type of event do you need to assume so that you can have the amount of response needed? Do you need to have enough MW to meet a 0.01 Hz event? Or is it a 0.1 Hz event? Of a 1 Hz event? Those amounts of available Frequency Response are completely different and could be vey unneeded if only small events occur.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Manitoba Hydro agrees that the BA should maintain a plan to maintain frequency reserves, however there is a concern that the proposed R5 will not address this issue. What criteria should be used to evaluate if the plan is adequate and meets the standard requirement? Is having an operating plan that meets the R1 requirements sufficient (i.e. median performance metric)? Or is it essentially requiring a 100% pass rate on all frequency events, when the existing standard requires the median response to be considered compliant? Additionally, there is no real-time monitoring requirement, how will an entity ensure the plan is functioning properly without measurement and mitigation?	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group supports MISO's comments in response to Question 1.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
• The anticipated cost and effort required to develop the necessary tools (for continuous monitoring of frequency response), infrastructure, documentation, and after-the-fact assessments required to support this requirement is not justified, given the evidence that frequency response performance has remained stable, if not improved, over the last 4 years (FRAA reports, Generator Surveys in 2017 and 2019). • At this time, The IESO would only support seasonal assessments of adequacy of Frequency Response as part of Resource Planning. • Furthermore, the 2020 State of Reliability Report says that, despite increasing percentages of inverter interfaced generation, frequency response has generally improved or remained stable for all Interconnections.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No

Document Name	
Comment	

First, while there may be concerns that a BA could perform for a partial year, the industry has not been shown any evidence that this is a widespread issue requiring a NERC Reliability Standard to address it.

Second, it is unclear what is needed from proposed Requirement R5. The requirement is vague with respect to what exactly is expected of a Responsible Entity. It immediately raises the question of how an entity is to determine what Frequency Response is available. NERC has not demonstrated how an entity could do that in any way, much less one that would be effective and compliant with the standard.

Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	

The MRO NSRF disagrees with the premise of the project; i.e. that there is a need to address concerns with the current performance metric for Balancing Authorities (BAs) due to “detuning.” To date, the MRO NSRF is not aware of any evidence that illustrates actual “detuning” events. As such, we respectfully ask the SDT to reconsider whether any modifications to BAL-003 are warranted, and if so, whether there is a more cost-effective way to accomplish these objectives aside from imposing new performance requirements on all BAs. **To the extent a Balancing Authority can demonstrate it has met its Frequency Response Obligation (FRO), the standard should provide Balancing Authorities with an option to maintain the current status quo.**

The MRO NSRF opposes the introduction of new requirement, R5, because the implementation of an Operating Process (day-ahead to seasonal) for frequency response reserves would require significant changes to existing operational planning processes that would outweigh any potential reliability benefits. This would include a daily process to quantify the expected amount of frequency response available to the system based on available resources. To our knowledge, many BAs’ capabilities to quantify frequency responsive reserves is limited to, at the most frequent, seasonal/ad hoc studies due to the complex nature of the resource models used to quantify frequency responsive reserves and would pose a significant challenge as there is currently no accurate representation of generators’ capabilities and performance. In short, implementation would be very burdensome and again, not worth the expected reliability benefit.

Furthermore, the existing BAL-003-2, requirement, R1, has proven sufficient since it’s inception in 2015/2016 in ensuring BAs meet their FRO requirements. Therefore, BAL-003 should provide Balancing Authorities with an option to maintain the current status quo.

Moreover, since May 2018, all new generators and generators performing material modifications are required to ensure the primary frequency response capability of their facility by installing, maintaining, and operating a functioning governor or equivalent controls pursuant to FERC Order 842 and in accordance with their Generator Interconnection Agreements (GIA), although this standard would ensure this equipment is configured and operating as expected.

Finally, the standard should recognize (and not penalize) BAs for any real-time governor performance, as there is no guarantee governors (even with the appropriate settings) will be able to respond in real-time as anticipated; e.g. due to forced outages, failure to start, etc. As written, the standard places the burden of frequency response compliance performance on the BA when the BA has no control over how the governors within its BA Area will actually respond in real-time.

Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
R5 focuses on administrative procedures rather than performance. These type of requirements keep being problematic when audits occur and the auditors focus on process quality and subjective approval of the processes. In the end, ATF performance should be the measure. The drafting team should be aware that non-compliance in this type of requirement can include lack of a signature, or failure to prove that someone actually reviewed a document annually, where in many cases, there will not be changes from year-to-year and will be no risk to reliability in most cases.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
While ISO-NE agrees generally with theconcept behind the proposal, ISO-NE belives that the proposal is too vauge for a standard. Standards require compliance and proof of compliance. What is the actual reliability benefit compared to the compliance burden?:	

Comments: Has the SDT found evidence that entities that have performed well in the first half of the year, subsequently "detune" their performance for the second half of the year because they have already met their annual median FRO? Given the evidence that frequency response performance has remained stable, if not improved, over the last 4 years (FRAA/SOR reports, Generator Surveys in 2017 and 2019), what is the evidence-based need or justification for the proposed requirement

Requirement 5 applies to the Operations Planning time horizon. As written, it could be interpreted as requiring a BA to compare *real-time* Frequency Response available to its Frequency Response Obligation. Therefore, ISO-NE recommends either removing the third bullet from Measure 5 or revise it to ensure that it clearly applies to only the Operations Planning time horizon, not real-time or same-day.

The SDT has not provided a proposed method by which BAs could feasibly quantify frequency response availability in the Operations Planning timeframe. It is very difficult to determine how much frequency response results from a certain dispatch, and it is even more difficult to do so for an unknown future dispatch (i.e., for the day-ahead timeframe). Is it sufficient to simply use the frequency response settings of each unit? What if the unit is at max? Does the dispatch need to ensure headroom? Observed FR depends on the units online, the loads online, types of loads, dispatch on units, DER, etc… There are a lot of factors that need to be considered in determining the actual available frequency response. Complex resource models with assumptions regarding resource operation on their real/reactive power curve appear to be required to achieve this. That kind of analysis is better suited for annual planning studies rather than operational planning timeframes.

Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	

R5 should be eliminated. The requirement is not performance based and will add work that could be applied to more productive activities.

Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	

NCPA agrees with and supports the response of the MRO NSRF to Question 1.

James Mearns, Northern California Power Agency, Segments 3, 4 & 5

Likes 0	
Dislikes 0	

Response

David Melanson - NB Power Corporation - 5

Answer	No
Document Name	

Comment

The requirement, as is, is too vague. It states that we would need an operating process to ensure that we should have frequency response at least equal to our FRO. It also indicates that it applies to the Operations Planning time horizon. There is no mention of real-time so it seems like this may be part of the day ahead process. The requirement doesn’t indicate the time horizon for which we need to ensure Frequency Response (FR) > FRO. Operations Planning can be 1 day to 1 year out. Does our process need to cover that entire time horizon?

It is vague on what our process should be. Do we have to ensure that FR > FRO for each hour in the day ahead plan? Or do we just need to show that on average FRM > FRO for the day? Does the process have to be hourly, or can it be every 4 hours, or 24 hours? It is not specifying a timeframe other than operations planning time horizon.

What if in real time FR < FRO? There is no mention to real-time so I assume that this would be ok. It is not clear whether we would have to commit additional generation in real-time to ensure FR > FRO. What if a generator trips in real-time? Do you have to commit additional generation to ensure FR > FRO or is it ok as this requirement should only apply to operations planning time horizon?

Another issue we have is that it is very difficult to determine how much frequency response you are going to get from a certain dispatch. Do you simply look at the frequency response settings of a unit? What if the unit is at max; does the dispatch need considered for each hour ensuring there is room? They really don’t give much for details on how to determine the expected frequency response of your system. It will depend on the units online, the loads online, types of loads, dispatch on units, DER, etc… There are a lot of factors that need considered in determining the actual frequency response you could expect.

In summary:

• The time horizon could be made more clear. It says operations planning time horizon but at what interval do you need to ensure FR > FRO? Also, is it just day-ahead or also week ahead? Any impacts to real-time operations if things change; which they often do?

• How often do you need to show Frequency Response > FRO?

• What if in real-time Frequency Response < FRO? Do you have to commit additional generation?

• What needs considered in ensuring Frequency Response > FRO? Is it simply using droop and dead-bands of units dispatched and ensuring there is room from where they are dispatched. How do you account for frequency responsive load and also for DER behind the meter that you may not be monitoring?

Likes 0	
Dislikes 0	

Response

Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
R1 is sufficient for the purpose of ensuring sufficient Frequency Response, and therefore R5 creates a redundant and unnecessary burden on the Responsible Entity.	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
R5 is a requirement to develop an Operating Process as part if its Operating Plan to address needed Frequency Responsive Reserve. This does not change the performance requirement in R1 in any way. An entity must still meet R1, and to do that, any necessary planning and operation of the resources must be done. There is no performance measure for this requirement, and it appears to be an administrative requirement.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC has concerns with the proposed standard in that the combination of R5, R6 and R7 fail to address points raised in the White Paper (and SAR) initiating this project: White Paper Page 2: Although BAs and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, tangible Real-time response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., GOPs) for provision of generator governor response; and	

White Paper Page 7: New GO/GOP requirements may require a GO/GOP to explicitly document and communicate Frequency Response capability, develop methods to explicitly monitor and communicate Frequency Response capability in Real-time, and demonstrate Frequency Response performance after-the-fact.

Because the SAR references observations about frequency response in the Western Interconnection, the SRC believes the SDT must consider how the proposed standard changes will impact reliability in the West. A majority of IBR resources in the West are not obligated to provide Frequency Response due to interconnection agreements predating FERC Order 842's effective date. BAs do not own any assets but R5 continues to put the primary compliance obligation for Frequency Response on them. The SRC does not interpret the SAR (Phase II) as intending to place only a notification obligation on GOs/GOPs, but rather the GOs/GOPs have an obligation to provide tangible Frequency Response and demonstrate authentic Frequency Response performance after-the-fact, as stated on Page 7 of the White Paper. The SRC believes the proposed changes to BAL-003 fall short of those recommendations.

Although R5 may be required from a tracking perspective, the SRC does not believe R5 should place a compliance obligation on the BA. As noted in later comments, it is not clear what course of action a BA would take if the Frequency Response fell short of the obligation as a result of inadequate generator performance. We suggest the reporting and tracking requirements be considered a 1600 data request process that can be better managed and adjusted if necessary.

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	No
Document Name	

Comment

CHPD does not agree with the proposed language in Requirement R5. CHPD believes that the current language in Requriement R1 ensures sufficient Frequency Response and therefore Requirement R5 creates an unnecessary administrative burden.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the MRO NSRF for question #1.

Likes 0	

Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MEC supports the first MRO NSRF comment: The MRO NSRF disagrees with the premise of the project; i.e. that there is a need to address concerns with the current performance metric for Balancing Authorities (BAs) due to “detuning.” To date, the MRO NSRF is not aware of any evidence that illustrates actual “detuning” events. As such, we respectfully ask the SDT to reconsider whether any modifications to BAL-003 are warranted, and if so, whether there is a more cost-effective way to accomplish these objectives aside from imposing new performance requirements on all BAs.	
Likes 0	
Dislikes 0	
Response	
Amy Jones - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
Propose that R5 be eliminated. The requirement is not performance based and will add work that could be applied to more productive activities.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	

PGE does not believe that there is a need for an Operating Plan requirement, nor does PGE believe the requirement is clearly implementable as written.

With regard to the need for an operating plan, PGE does not believe the standard as written incentivizes entities to “detune” their performance. BA’s do not know which events will be selected or their resulting FRM until after the compliance year is over. Even the preliminary selections that are made throughout the year come out well after the compliance quarter in question and then are subject to change at the end of the year. For that reason a BA can not know for sure what its performance to date is until after the entire year is complete. Due to the somewhat random nature of the measurement methodology, where large swings in renewable energy or dynamic schedules can result in strong actual frequency response being overshadowed by unrelated generation movement, and the unknowns regarding how many events may be selected in a given quarter, there is enough uncertainty on an event by event basis that it is not reasonable for a BA to assume they can simply detune their resources for the remainder of a year. Furthermore PGE is part of a large Frequency Response Sharing group which has its own internal requirements and quarterly assessments which provide an additional layer of scrutiny to the BA performance. As a member of that group PGE has had visibility of the performance of a sizeable cross section of the BA’s across the Western Interconnection since BAL-003 has been active, and has not seen any evidence of members detuning their response in response to strong performance early in the year.

Concerning the proposed language for the Operating Plan requirement, once again the nature of the standard as written makes it difficult or impossible to clearly define the actions that each unique BA should take to meet the standard. Unlike BAL-002-3 R2 which is sited above and which has a clearly defined MW value for the Contingency Reserve Obligation, which is a quantity easily metered in real time, BAL-003 does not have a clear MW requirement nor is it simple to define one that would be applicable to all entities. Further, compared to Contingency Reserves, Frequency Reserves are less well defined and more difficult to measure, as many frequency responsive resources will have different MW/0.1Hz responses based on both the starting frequency and the magnitude of the event, which will not be known until after an event occurs, meaning a real time measurement of available Frequency Response can be essentially impossible for some resources. Some BA’s have frequency responsive load or generation that is not explicitly metered as such but based on historical performance could be used as part of their overall assessment. Simply having Frequency Response available equal to the Frequency Response Obligation does not ensure that a BA will pass the standard, and there are not clear requirements for how many MW are needed to meet that obligation until after events are selected.

Furthermore, as a member of an FRSG, PGE coordinates its BAL-003 compliance with several other entities. It is the FRSG that must meet the FRM requirement, not the individual BA. To date that FRSG has not had an FRM less negative than FRO for a single event since the standard became active.

Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

While Dominion Energy supports the Requirement, for a Balancing Authority, the language of R5 as written creates potential risk of non-compliance for not following the operating plan during high load or maintenance seasons when its generation fleet is near Pmax. We suggest that clarification be provided to stress the reliability objective and not create a compliance issue for the BA in a situation that is not under their control.

Likes 0	
Dislikes 0	

Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM agrees with integrating an operating process to address frequency responsive reserves into the operating plan.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
The requirement to have an Operating Process specifically for Frequency Responsive reserves seems unnecessary given that Balancing Authorities are already required to develop Operating Plans for the next-day that address capacity and energy reserve requirements, per TOP-002-4 R4.4.4. and Frequency Response reserves is an energy reserve requirement.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports the comments of NAGF.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees that the proposed Requirement R5 addresses many concerns related to the current performance metric for Balancing Authorities (BA). BPA believes a median performance metric is not a real-time requirement. Requiring an operating plan, similar to BAL-002-3, Requirement R2, brings the BAL-003 standard closer to a real-time requirement. BA's would now plan for, and notify, how they intend to meet their Frequency Response Obligation (FRO) in the next hour. BPA understands that specific reserve levels held will vary from BA to BA. Interpretations could vary on this requirement but, at a minimum, BAs will document and convey how they intend to keep Frequency Response equal to, or greater than (in absolute value), the BA's FRO available for maintaining system reliability.	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Although, from a monitoring and audit perspective there is no harm in creating additional requirments, creating a requirement to have a process to prepare for something does not resolve the reliability issue inherent in the actual performace. However, requiring the applicable entity to implement and follow the procedure can help resolve the reliability issue IF the entity creates an effective process and follows it. The VSLs indicate that **failure** to implement is a high VLS, so this seems to address the issue.	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees with the language in Requirement R5. Texas RE recommends the SDT consider adding more detail for the minimum requirements needed in the Operating Process, such as BA requirements for how quickly a GO should notify the BA for Governors out of service, BA requirements for a proportional vs a stepped response provided by the Governors, possible exemptions for specific types of units, etc.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG concurs with NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the submitted NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Consistent with EEI comments for the Project 2017-01 White Paper, EEI supports proposed Requirement R5 that requires BAs to have an Operating Process as part of their Operating Plan. We further support the Requirement's language that requires BAs to develop, review, and maintain annually, and implement that Operating Process.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports EEI's comments that support the proposed Requirement R5.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Requiring an additional operating process within the operating plan seems less effective than performance measures.	

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comment posted by EEI for Question 1 On behalf of Exelon, Segments 1 and 3	
Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the proposed new Requirement 5 of Balancing Authorities having an Operating process as a part of its Operating Plan to address Frequency Response reserves.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	
Document Name	
Comment	

We have no opinion on this issue.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	
Document Name	

Comment

No Comment - BHC is not a BA

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	

Comment

No Comment - BHC is not a BA.

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	
Document Name	

Comment

No Comment - BHC is not a BA

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6

Answer	
Document Name	

Comment

BHC is not a BA

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT supports the comments filed by the ISO/RTO Council's Standards Review Committee (SRC) and adopts those comments as its own.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation has no proposed comments.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no proposed comments. Kimberly Turco, on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

2. To address the concern that the Balancing Authorities are not seeing the FR expected, the drafting team has proposed Requirements R6 and R7. Requirement R6 is modeled after the VAR-002-4.1, Requirement R1 and requires the Generator Operator to operate generators with the Governor in service unless the Balancing Authority has been notified that the Governor is out-of-service. Do you support adding proposed Requirement R6 to BAL-003? Please provide the reasoning or justification for your position in the comments.

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon concurs with the comment posted by EEI for Question 2

On behalf of Exelon, Segments 1 and 3

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

The proposed language says “frequency responsive controls in service” – it is not entirely clear that a GOP who has been ordered into an operating state that effectively removes headroom would be considered compliant in this situation, since the governor is in “in service” but will not provide a response – is it “responsive” then? Since the BA has the responsibility for achieving overall FRO, they should have discretion over whether a unit is expected to provide PFR or not. While we generally agree that unit governors should be in service and operating as much as possible, placing the frequency controls “in service” does not necessarily ensure that primary frequency response is available from that generator. For example, some gas turbine generators with duct burners have dampened gas turbine frequency response when duct burners are on line, and units that are ordered to run at their maximum power output cannot regulate in the upward direction. This is something the BA is aware of, and the BA calls for the duct burners to be put on line, or calls for certain units to be run “at the top”. The requirement language should clarify that it is acceptable for the unit to not be responsive if the BA has instructed them to operate in that condition. Given that this draft introduces a definition for “Governor” into the Glossary of Terms, why could that not be used here instead of “frequency responsive controls”?

Likes 0	
Dislikes 0	

Response

Amy Jones - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
Clarification language should be added so that this requirement does not apply to minimal changes, such as changes in the percent of a resource that is pseudo tied from one BA to another. As an alternative, language could be added that this action is not necessary if both BAs agree it is not necessary. Grant PUD believes it is important to weigh the workload involved with the benefit from a requirement that only applies for part of a year.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy contends that R6 is unnecessary because the BA already has the capability of requiring Generator Operators to provide this data in their data specification created for TOP-003-4 R2. Allowing the BA to require exactly the data they need as inputs for the processes they put in place to handle frequency response provides much greater flexibility for the BA to meet its frequency response objectives. In addition, there are currently no BAL standards that have GOP/GO applicability and adding those applicable entities to this standard could create confusion when a mechanism to get this data already exists. Adding a requirement for a GOP in this standard could create a double jeopardy scenario if a BA already requires the same or similar data be provided under TOP-003-4 R2. Lastly, we do not believe this is an actual problem that needs to be solved. The NERC 2021 LTRA report clearly states in its Key Findings that “Frequency response is expected to remain adequate through 2023.” Similar findings in the 2022 Frequency Response Annual Analysis currently routing for approval by the RSTC suggest this is not an issue that needs to be dealt with by creating new standard requirements.	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	

Requirement R6 is a good concept and modeled after the VAR standard which provides consistency for users. It should be clarified if this is intended to require all applicable units have a governor or frequency responsive controls (existing and future, conventional and wind/solar) or not. Applicability should be limited to BES units.

Governor is a well known term in the generation industry for conventional units. A standard definition is particularly important when droop and deadband requirements are included (R7). IEEE standards provide definitions for Governor, Droop and Speed Deadband. The proposed governor definition relies on the Primary Frequency Response definition which is only in the frequency restoration direction. The proposed definition could create confusion between governors and frequency responsive controls. A governor's primary function is speed control which turns into frequency response when a synchronous generator is connected to the system. Control response may be in the direction desired but initial frequency response may be opposite in response to an event, due to turbine design (drop in steam or water pressure when a valve is opened for example). It appears this definition is concerned with the primary frequency control response. CHPD requests that this should be clarified.

Requirement R6 mixes the two terms. The GO/GOP is required to have "frequency responsive controls" in service. The exception is when the GO/GOP notifies the BA of a "Governor" status change (in- service, out- of- service). This implies that Governor means frequency responsive controls. Is the requirement to have a Governor in service or some sort of frequency responsive control that has governor characteristics of droop and deadband? This creates a challenge for R7 which has governor specific terms and requirements. We suggest the use of an industry standard definition of governor (IEEE 125 and 1207 have definitions that would work) and eliminate the term frequency responsive controls for application to conventional units. If non-conventional units are to be included (wind and solar for example) then more complex definitions should be crafted to include controls that are not a governor but have characteristics of a governor.

Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company does not support the current language of proposed Requirement R6 and supports the EEI comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI generally supports the intent of Requirement R6 but disagrees with the current language of Requirement R6 because it is not consistent with FERC Order 842. In FERC Order 842, the Commission specifically limited the directive to newly interconnecting large and small generating facilities and did not require existing generating resources to supply primary frequency response if they were not designed to do so. EEI also notes that the NERC 2022 State of Reliability Report concludes that "frequency response remained stable or improved across all interconnections" (see Executive Summary; page vii, next to last paragraph). In addition, the NERC Frequency Response Annual Analysis reaches a similar conclusion.

Additionally, EEI disagrees that Requirement R6 has been modeled after VAR-002-4.1. The concerns with this requirement include the following:

1. R6 should be more closely modeled after the Requirements in VAR-002-4.1. In the proposed changes to BAL-003, the two Requirements have been consolidated into a single requirement. R6 now contains requirements 1) to turn on frequency responsive controls and 2) to report a change in the status of the Governor while the VAR-002 Reliability Standard has separated these into different requirement.
2. EEI recommends using consistent terminology. In Requirement R6 the SDT uses the term "frequency responsive controls", which an undefined term, and Governor within the same Requirement. For consistency, EEI suggests using the term Governor.
3. Footnotes should not be used for describing conditions within enforceable Requirements because they can be easily missed.
4. An exception should be added to address existing generating resources that were never designed to provide primary frequency response, or have been otherwise exempted.

To address these concerns, we offer the following language:

R6 Each Generator Operator shall operate each generating unit/generating facility that is connected to the interconnected transmission system with **their Governor in service, unless the generator is:**

- **Being operated in start-up, shutdown, or testing mode pursuant to a Real-time communication; or**
- **Being operated under a procedure that was previously reported to the Balancing Authority; or**
- **The generating unit as designed does not have primary frequency response capability, or is otherwise exempted from providing this capability.**

RX **Each Generator Operator shall notify the Balancing Authority of a status change on a governor that is online and released for dispatch within 30 minutes of the discover of the change. If the status has been restored within 30 minutes of the discovery of the change, then the Generator Operator is not required to notify the Balancing Authority of the status change.**

[Violation Risk Factor = Medium] [Time Horizon = Realtime Operations]

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 1,3,5

Answer	No
Document Name	

Comment

The BA should have the authority to exempt governors from being in service. Examples include, the steam turbine of a combined cycle train that won't be able to provide PFR as when in valves wide open mode, units performing test, or units that have informed the BA of governor control issues that the BA may want online for MW rather than being forced offline to repair governor components.

Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the submitted NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro is supportive of the intent of Requirements R6 and R7; however, additional clarifications are requested to clarify compliance obligations. The Requirement R6 as drafted appears to apply to generating facilities that are not part of BES (i.e. "… each generating unit/generating facility that is connected to the interconnected transmission system…"). The Requirement R7 uses the term "resource" to identify the scope of applicability. BC Hydro suggests that consistent language be used in Requirements R6 and R7. BC Hydro requests that the drafting team clarify the applicability scope and subsequently revise the wording of Requirements R6 and R7 as appropriate. BC Hydro's understanding is that the intent of Requirement R6 is to mandate that the generating units provide Primary Frequency Response. BC Hydro suggests that it is better to define the status of a Governor, i.e. when a Governor is considered "in-service" and "out-of-service", to help ensure R6 is implemented as intended.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No

Document Name	
Comment	

The North American Generators Forum (NAGF) is an independent, member-driven organization with over 70 GO/GOP member companies (~53% of BES Generation Capacity in North America). The NAGF's member-driven collaborative approach to open-source collaboration and information exchange with generator industry professionals results in a unique generator specific perspective on current and emerging grid reliability risks and corresponding NERC Relaibility Standards.

In general, the NAGF agrees with the principles proposed in BAL-003-3, but recommends that the Standard Drafting Team (SDT) consider the following:

1. Consistent language between BAL-003-3 II R6 & M6 & RSAW – NAGF offers that 'frequency responsive controls' and 'frequency responsive mode' may not be interpreted the same way. Though a site may have frequency responsive controls enabled / in service, there may be certain operational conditions (see *NAGF Operational Example*) where the unit is not responsive to grid frequency, despite the in-service status of their frequency responsive controls. The NAGF recommends that the SDT change the 'frequency responsive mode' reference in M6 to be consistent with the 'frequency responsive controls' language in R6 and the draft RSAW**.**

NAGF Operational Example: Per R6, Combined cycle plant CTGs typically run with their governors (i.e. frequency responsive controls) enabled / in service. However, in certain operational situations (i.e. firing temperator limit mode of operation) there will be no response to grid frequency which makes demonstrating compliance with M6 difficult, if not impossible.

R6 - Each Generator Operator shall operate each generating unit/generating facility that is connected to the interconnected transmission system with **frequency responsive controls in service** when the generating unit/generating facility is online and released for dispatch, unless the Generator Operator has notified the Balancing Authority as soon as practical but within 30 minutes of the discovery of a Governor status change (in-service, out-of-service).

M6 - The Generator Operator shall have evidence to show that it notified its associated Balancing Authority any time it failed to operate a generator in the **frequency responsive mode** when the generating facility was online and released for dispatch.

R6 RSAW (Compliance Assessment Approach) - Verify the entity operated each of (or a sample of) its generating unit/generating facilities that are connected to the interconnected transmission system with **frequency responsive controls in service** when the generating unit/generating facility was online and released for dispatch, unless the Generator Operator notified the Balancing Authority as soon as practical but within 30 minutes of the discovery of a status change (in service, out of service) of a Governor.

2. Allowance for exemption – Like NERC, the NAGF recognizes that our grid is in a state of transformation. Given the diversity of today's generation capabilities and consistent with VAR-002, the NAGF recommends that the SDT clearly articulate in supplemental guidance that exceptions based on capability or other are allowed but that they must be reported to the BA. In addition to entity identified and declared exemptions, the STD may want to consider adding language tht allows the BA to identify exemtions. NAGF populated examples of entities that may request exemption are as follows :

a. Nuclear facilities whose frequency response capabilities are currently limited by Nuclear Regulatory Commission

b. Entities not applicable to FERC Order 842, which though technically capable of providing frequency support may not have enabled it because it was not required as part of their interconnection

c. Entities with equipment and / or operational limitations – as approved by BA

d. {C}Other entities as determined by BA; As this standard becomes applicable to generators, there may be some challenges, specifically for intermittent resources which may result in the BA being inundated with notifications. The BA should have the flexibility to exempt (perhaps on an annual basis) certain entities or categories of generators from this standard.

Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
Further clarification is needed regarding the authority of Balancing Authorities to exempt a given Generator Operator from providing frequency response. As currently written, R6 does not clarify whether this authority exists or has been removed from the Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
David Melanson - NB Power Corporation - 5	
Answer	No
Document Name	
Comment	
FERC, under the Pro Forma Tariff, recommend nuclear facilities be exempted from frequency response requirements. R6 and R7 don’t have exemption provisions which may contradict the FERC Pro Forma Tariff (detailed in FERC Order 842). FERC allows this exemption but NERC doesn’t under these proposed requirements. Refer to FERC Order 842 for additional details on the Nuclear exemption. Also, a BA with the requirement to ensure FR > FRO may no longer want to grant exemptions to nuclear units. FERC and NERC seem to contradict here a little. I would want more clarifications in R6 and R7 for Nuclear units.	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	

NCPA agrees with and supports the responses of PPL NERC Registered Affiliates & MRO NSRF to Question 2.

James Mearns, Northern California Power Agency, Segments 3, 4 & 5

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	

The language of R6 seens to establish a **two-part requirement** for (1) "**frequency responsive controls**" – and (2) **Governor status change,** or are these terms intended to mean the same thing? The state of the governor being offline while the unit is online does not exist. This needs to be redefined.

This BAL-003-3 proposed definition of Governor does not reference control modes or "frequency responsive controls".

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	

No, BAL standards are aimed at Balancing Authorities not Generator Operators. This requirement should be aimed at the BAL ensuring that the generators in their footprint operate in a mode that allows them to meet their BAL obligations. Having the BAL focus on Generator Operators starts to shift the obligations of the Balancing Authority to someone else for non-performance, and has a tendancy to undermine service agreements and market rules.

Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	

Answer	No
Document Name	
Comment	

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.

Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	

The MRO NSRF agrees it is important for GOPs to operate their units with their frequency responsive controls in service when the generating unit/generating facility is online and released for dispatch. Equally important is a requirement to operate the unit in such a manner that the governor is not bypassed, so the unit is responsive to system frequency based on the standard settings documented in R7.

That said, the MRO NSRF disagrees with the proposed requirement for the GOP to notify its BA within 30-minutes of discovery of a change in its governor status (Time Horizon = Real-Time Operations). If the intent is to support the Operations Plan in the Operations Planning horizon (day-ahead to seasonal), then the SDT should modify the notification timeframe to align with a Time Horizon = Operations Planning (day ahead to seasonal).

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	No
Document Name	
Comment	

No, proposed Requirement R6 is unnecessary. Since the FR in all Interconnections has either improved or stabilized since BAL-003 became effective, there is no reason to require GOs to take action.Furthermore, this requirement would only require GOs to provide information. Balancing Authorities can already request this information through TOP-003 R2.

Likes 0	
Dislikes 0	

Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
TEM supports the comments of Talen Generation.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Comments: Talen Energy agrees with the principles proposed in BAL-003-3, but with certain clarifications, perhaps best put in a Guidance section of the standard: 1. R6 mandates having, "frequency responsive controls in service," while M6 references, "the frequency responsive mode," which is not necessarily the same thing. Combined cycle CTGs for example run with their governors enabled, thereby satisfying R6, but if at the firing temperature limit there can be no response to a reduction in grid frequency, making the M6 outlook uncertain. That is, the firing temperature limit mode is not a frequency responsive mode. BAL-003-3 should explicitly permit such operation (as well as STG running valves-wide-open) and also state the point verbally made in NERC's 8/25/2022 webinar that NERC does not seek "headroom." 2. The standard should have an exemption for nuclear units, since their governors are blocked as required by the NERC. This point is covered in R7 by allowing GO/GOPs to declare that, "The resource as designed does not have frequency response capability," but it is presently unaddressed for R6.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	

Xcel Energy supports the comments of EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports MISO's comments in response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Manitoba Hydro does not agree with adding this requirement to all generation resources in the BA footprint. This wide requirement (applicable to all generation resources) may add a compliance burden, the potential for penalizing GO/GOP, and a potential to have significant data exchange requirements between the generator and BA with not necessarily increasing Frequency Response for the non-reserve generation resources. Manitoba Hydro believes that these data exchange requirements should only be between the identified reserve resource facilities with functional frequency response and BA. The requirement should clearly state that this requirement applies only to a governor with enabling and disabling frequency control mode of operations and not after the fact governor response failed to respond to a frequency event due to control failure.	
Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	

Comment	
Ameren agrees with and supports the comments of NAGF.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy agrees with MISO's submitted comments for question 2. Additionally, FAC-002 has requirements for reporting changes to the interconnection, and MOD-027 has requirements related to making changes to the governor model that must be reported. The proposed BAL-003 change is redundant.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
The governor state specified in R6 does not exist if the unit is synchronized. Synchronized speed control in manual requires too large of a frequency band (~4 Hz) on a stable system. If the unit is synchronized, the governor is in service. If the terms referring to the Governor in-service and out-of-service are referring to something besides manual speed control they need to be defined.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	

Comment	
While a mandatory requirement assigned to generators is a step in the right direction, an accompanying movement to make frequency response a market product akin to reactive support is needed. BAs will not need to concern themselves with FR expected if made a reliability service in a similar fashion to reactive support.	
Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments provided for this project.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends the M6 Measure be revised to align with the requirement to have frequency responsive controls in service at all times, i.e., “the Generator Operator shall have evidence to show that its generating unit/generating facility was connected to the interconnected transmission system with frequency responsive controls in service,” rather than only requiring documented notification of the failure of frequency response mode. Alternatively, Reclamation recommends the R6 Requirement be revised to state the notification requirement, i.e., “Each Generator Operator shall notify its associated Balancing Authority within 30 minutes any time it fails to operate a generator in the frequency responsive mode,” which would align with the currently proposed language of M6.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	

Comment

FirstEnergy support EEI's comments, which state:

EEI supports the intent of Requirement R6 but disagrees with the current language of Requirement R6 because it is not consistent with FERC Order 842. In FERC Order 842, the Commission specifically limited the directive to newly interconnecting large and small generating facilities and did not require existing generating resources to supply primary frequency response if they were not designed to do so.

Additionally, EEI disagrees that Requirement R6 has been modeled after VAR-002-4.1. The concerns with this requirement include the following:

1. R6 should be more closely modeled after the Requirements in VAR-002-4.1. In the proposed changes to BAL-003, the two Requirements have been consolidated into a single requirement. R6 now contains requirements 1) to turn on frequency responsive controls and 2) to report a change in the status of the Governor while the VAR-002 Reliability Standard has separated these into different requirement.

2. EEI recommends using consistent terminology. In Requirement R6 the SDT uses the term "frequency responsive controls", which an undefined term, and Governor within the same Requirement. For consistency, EEI suggests simply using the term Governor.

3. Footnotes should not be used for describing conditions within enforceable Requirements because they can be easily missed.

4. An exception should be added to address existing generating resources that were never designed to provide primary frequency response, or have been otherwise exempted.

To address these concerns we offer the following language:

R6 Each Generator Operator shall operate each generating unit/generating facility that is connected to the interconnected transmission system with Governor in service unless the generator is:

• Being operated in start-up, shutdown, or testing mode pursuant to a Real-time communication; or

• Being operated under a procedure that was previously reported to the Balancing Authority

• The generating unit as designed does not have primary frequency response capability, or is otherwise exempted from providing this capability

RX Each Generator Operator shall notify the Balancing Authority of a status change on a governor that is online and released for dispatch within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Balancing Authority of the status change.

[Violation Risk Factor = Medium] [Time Horizon = Realtime Operations]

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No

Document Name	
Comment	
FERC, under the Pro Forma Tariff, recommend nuclear facilities be exempted from frequency response requirements. R6 and R7 don't have exemption provisions which may contradict the FERC Pro Forma Tariff (detailed in FERC Order 842). FERC allows this exemption but NERC doesn't under these proposed requirements. Refer to FERC Order 842 for additional details on the Nuclear exemption. Also, a BA with the requirement to ensure FR > FRO may no longer want to grant exemptions to nuclear units. FERC and NERC seem to contradict here a little. I would want more clarifications in R6 and R7 for Nuclear units.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
R6 does not seem achievable based on the expectation of notifying for governor status changes; additional specificity is required or suggest the following be removed from R6: "unless the Generator Operator has notified the Balancing Authority as soon as practical but within 30 minutes of the discovery of a Governor status change (in- service, out- of- service) of a Governor".	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP agrees with the substance of the proposed R6, frequency response controls (governor) may be in service, but a unit may be operating in a mode or at a temperature/pressure limit that prevents the frequency response from being effective. The primary frequency response may be muted or impacted by other operating conditions. Clarification of "in service" or "out of service" may be required in consideration of the above. Additional clarity is needed within R6 to indicate whether an operating governor that does not respond to a frequency excursion due to an operating condition, is considered a violation.	
Likes 1	Seattle City Light, 4, Li Hao

Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Yes, AZPS supports the addition of Requirement 6. However, in proposed Requirement 6, the term “discovery” of a Governor status change appears to state that once a Generator Operator discovers and/or becomes aware of the status change, that only when discovered or becoming aware of a change, the GOP shall then notify the Balancing Authority within 30 minutes of discovering/becoming aware. Rather than, once the generating unit’s frequency response status has changed, within 30 minutes of such change, GOP shall notify the Balancing Authority (language/requirement similar to VAR-002-4.1, R3). The term “discovery” of a Governor status change is ambiguous.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MEC supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	

The SRC agrees a requirement for GOPs to operate with governors in service is the only way to ensure adequate frequency response. However, equally important, is requiring the GOP to operate the unit in a manner that does not bypass the governor, so the unit responds to system frequency based on the settings in R7.

The SRC requests the SDT add a requirement for the GOP to return frequency response controls to "in service" as soon as possible after having the frequency responsive controls not in service. A unit/facility's frequency response *performance* will not be evaluated during start-up, shutdown and testing but the unit/facility should have its frequency response controls in service to the fullest extent possible. BAs can include a definition of "released for dispatch" for their specific footprints in their Operating Process pursuant to R5. The SDT may remove Footnote 1 as a result of the suggested revision.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation is supportive of the NAGF comments. Constellations specifically asks for further clarification on the notification requirement when a unit is running in eco-max\HSL and there is no ability to respond with additional MW to an event, although they can reduce MW at that point. Constellation suggests further clarification on the notification requirement regarding similar conditions.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation is supportive of the NAGF comments. Constellations specifically asks for further clarification on the notification requirement when a unit is running in eco-max\HSL and there is no ability to respond with additional MW to an event, although they can reduce MW at that point. Constellation suggests further clarification on the notification requirement regarding similar conditions.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	Yes
Document Name	

Comment

The proposition is in red. Frequency responsive controls should be out of service if instructed by the Balancing Authority:

R6: Each Generator Operator shall operate each generating unit/generating facility that is connected to the interconnected transmission system with frequency responsive controls in service when the generating unit/generating facility is online and released for dispatch1 unless the Generator Operator has notified the Balancing Authority as soon as practical but within 30 minutes of the discovery of a Governor status change (in-service, out-of-service) of a Governor or as instructed by the Balancing Authority.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG concurs with NPCC RSC.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

Southern Indiana Gas & Electric Company (SIGE) supports the proposed Requirement R6 - including the timeframe for notifying the Balancing Authority. However, SIGE has provided feedback in Question 6 regarding the Violation Risk Factors for R6. Additionally, SIGE recommends the following updates to Measure M6:

- The Generator Operator shall have evidence to show that it notified its associated Balancing Authority ***within 30 minutes of discovering a Governor status change in accordance with Requirement R6.***

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	Yes
Document Name	

Comment

Proposition in italics. Frequency responsive controls should be out of service if instructed by the Balancing Authority:

R6: Each Generator Operator shall operate each generating unit/generating facility that is connected to the interconnected transmission system with frequency responsive controls in service when the generating unit/generating facility is online and released for dispatch1, unless the Generator Operator has notified the Balancing Authority as soon as practical but within 30 minutes of the discovery of a Governor status change (in- service, out- of-service) *or as instructed by the Balancing Autority.*

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC

Answer	Yes
Document Name	

Comment

SMUD agrees with the proposal to add R6 to BAL-003 to help ensure that Balancing Authorities see the expected Frequency Response. However, the proposed language in R6 does not model VAR-002-4.1 like is should because the “exemption” clause is missing. A Generator Operator who has received a written exemption from its Balancing Authority should not have to meet the new R6 requirement, like the exemption clause allowed in VAR-002-4.1 R1 between the Generator Operator and its Transmission Operator. Adding the exemption clause to BAL-003 R6 would give Balancing Authorities the flexibility to grant an exemption, particularly in cases involving legacy renewable generators or where the generating resource does not have frequency response capability. Furthermore, adding the exemption clause would help align R6 with the proposed R7 language which grants the

Generator Owner an exception for meeting the droop and deadband settings in cases where “the resource as designed does not have frequency response capability.”

To align R6 with R7, and BAL-003 with VAR-002-4.1, the proposed language in R6 should be changed as follows.

“Each Generator Operator shall operate each generating unit/generating facility that is connected to the interconnected transmission system with frequency responsive controls in service when the generating unit/generating facility is online and released for dispatch1, unless the Generator Operator has notified the Balancing Authority as soon as practical but within 30 minutes of the discovery of a Governor status change (in-service, out-of-service) ***or the Generator Operator has received a written exemption from its Balancing Authority*** [emphasis added]”

Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
BHC has no concern with the addition of Requirement R6 and the notification if Governor is out of Service.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
BHC has no concern with the addition of Requirement R6 and the notification if Governor is out of Service.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes

Document Name	
Comment	
BHC has no concern with the addition of Requirement R6 and the notification if Governor is out of Service.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHC has no concern with the addition of Requirement R6 and the notification if Governor is out of Service.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ISO-NE generally agrees with the concept in Requirement 6. However, as written, R6 requires the GOP to operate a unit/facility with frequency responsive controls in service *unless it notifies the BA*. If the GOP notifies the BA its frequency responsive controls are not in service, the requirement no longer applies. ISO-NE believes the SDT should add a requirement for the GOP to return the frequency responsive controls to "in service" as soon as possible. Though, what does "in-service" mean? Does it mean as stated in M6 "operate a generator in the frequency responsive mode when the generating facility was online and released for dispatch"? A clear definition of "in-service" is required. Additionally, ISO-NE believes a GOP *should* operate in frequency responsive mode during start-up, shutdown and testing to the extent possible (although ISO-NE recognizes the generator's *performance* should not be evaluated during start-up, shutdown and testing). There is no explicit exception process noted in R6 or R7. Does this put BAL-003-3 in conflict with FERC 842 (that allows exemptions for Nuclear resources)?	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Although the amount of time and the number of generators that might lose governors is probably minimal, and it is unclear what the BA is to do with this information, WECC agrees that it is beneficial to have a requirement that the generating resource have its frequency responsive controls in service.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees with the addtion of the new Requirement R6. BPA belives it codifies the intent of FERC Order No. 842 (issued in 2018) into a reliability standard. As stated in Order 842, BPA agrees with "new large and small generating facilities, including both synchronous and non-synchronous, interconnecting through a LGIA or SGIA to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection."	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
This only applies to generators that have governors and is a small piece of coordination and communication to verify that is in or out-of-service.	
Likes 0	
Dislikes 0	

Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
R6: Each Generator Operator shall operate each generating unit/generating facility that is connected to the interconnected transmission system with frequency responsive controls in service when the generating unit/generating facility is online and released for dispatch1, unless the Generator Operator has notified the Balancing Authority as soon as practical but within 30 minutes of the discovery of a Governor status change (in- service, out- of-service) or as instructed by the Balancing Autority.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM is in support of maintaining governors in the frequency responsive mode for interconnected and dispatchable generators as written in R6. PNM also agrees with the timeline to notify the Balancing Authority for governor change in status.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Yes, we support the addition of this standard. It may require more substance, however. The requirement does not give leeway to the BA to exempt facilities from this requirement even if they have frequency responsive controls. Engaging *all* facilities with frequency responsive controls could cause a BA's response to increase dramatically which in turn could cause its Bias to increase out of proportion to its load and generation size within the	

Interconnection. Bias increases of this nature can pose operational difficulty for ACE control to BAs especially if frequency responsive controls reside on facilities that do not have true dispatch capability, like renewables.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	
Document Name	
Comment	
The obligation of a Generator Operator to notify the Balancing Authority of the loss of a critical control component is a logical and simple step to follow. If this gets implemented via the proposed Requirement R6, and not via the existing data specification mechanism provided by TOP-003-4 R2, then clarification will then be needed on what consitutes a "governor status change". Is it specific to droop action?	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT supports the comments filed by the ISO/RTO Council's Standards Review Committee (SRC) and adopts those comments as its own.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	
Document Name	
Comment	
Texas RE agrees with the concepts drafted in Requirement R6. Texas RE recommends that the requirement for the Governor to be in-service, or if not, notify the BA, should be a stand-alone requirement so that it is clear there is an action that needs to be taken.	
Likes 0	
Dislikes 0	
Response	

3. To address the concern that the Balancing Authorities are not seeing the FR expected, the drafting team has proposed Requirements R6 and R7. Requirement R7 states that the Generator Owner is responsible to ensure minimum settings for the Governor droop and deadband or notification to the Balancing Authority if the settings are not within these minimum settings. Do you support adding proposed Requirement R7 to BAL-003? Please provide the reasoning or justification for your position in the comments.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP disagrees with the proposed R7, as more clarity is needed regarding what circumstances would qualify for exemption of requirement settings (similar to that provided in BAL-001-TRE in R9.3 and R10.3). Specifically, additional language is needed to clearly identify the operational and/or technical constraints which would allow for exemptions or exclusions.

The proposed 0.036 Hz deadband could cause operational issues for some units. Additional clarity is needed, using either definitions or examples, as to exactly what resources as designed will not have frequency response capability.

Likes 0	
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	

If FERC under the Pro Forma Tariff (detailed in FERC Order 842) are requiring a dead-band of 36 mHz and droop of less than 5%, is the duplicative NERC requirement required?

Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Reclamation recommends Requirement R7 be revised to specify a timeframe within which the Generator Owner must notify its Balancing Authority. Reclamation also recommends Measure M7 be revised to include documentation of any notification provided to the Balancing Authority if an exception is claimed. Reclamation recommends Requirement R7 should apply to Generator Operators or in combination with Generator Owners.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments provided for this project	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
CEPM does believe the industry has had enough time to police the problems of frequency response and there needs to be some type of NERC Standard/Requirment to help support the efforts for frequency response. However it does feel that there are already standards in place to manage both the proposed standards in BAL-003-3 for the GO in R7, For instance. The purpose of MOD-027 is to...'accurately represent generator unit real power response to system frequency variations'. It seems like the governor and frequency response expectations should be covered under these requirements in MOD-027 and not included separately in BAL-003.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	

Comment	
The proposed R7 language is not clear on the definition of "resource". Is the term intended to apply to the individual turbines, or to the powerblock overall? This is a concern in cases such as CCGT units where the individual steam turbines typically don't respond in a quick enough fashion because they have to follow the output of the gas turbines.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports the comments of NAGF.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
For a given droop setting, the governor response will vary according to the base that is used in the governor to convert power from MW to "per unit" value. Also, mechanical and analog governors, even if set to 5% droop, may result in a slightly different response than expected. For this reason, a tolerance (e.g., ±1%) should be allowed to cover these cases.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment	
Manitoba Hydro is in support of a requirement for the BA to request the governor droop settings (and the droop types and based value) and total measured deadband including any intentional deadband settings (or functional equivalent). However, Manitoba Hydro does not support setting any governor droop and deadband target requirements in this standard. These requirements should be addressed in MOD-027. Also, Manitoba Hydro believes that any governor control settings change should be addressed by the Planning Coordinators as it may have much wider system implications.	
Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	
Response	

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Comments: Talen Energy agrees with the numerical values specified in R7, but with certain clarifications, perhaps best put in a Guidance section of the standard:

1. Deadband consists of an intentional portion (i.e. settings) and an inherent portion (due to hysteresis, control linkage backlash etc). BAL-003-3 should state that R7 pertains to only intentional deadband, and that GO/GOPs are not expected to conduct disturbance response tests to identify the total deadband.

2. Generation units with mechanical-hydraulic controls (MHC) have no setting for intentional deadband. BAL-003-3 should state that this falls under the exceptions clause of R7, as opposed to requiring disturbance response testing to identify the inherent deadband value. This is especially the case since, if finding an inherent deadband greater than 36 mHz, there is no means of adjusting it.

3. The term, “Governor capability,” in R7 is unclear. “Capability” generally refers to what a generation unit can do, and the governor is just one element in this respect. The response to a disturbance of a CTG and its governor are nearly the same, but for a fossil unit the need to boil more water (in a system weighing millions of pounds) creates a significant governor-vs-total unit. Use of the “throttle reserve” allows a quick response for fossil

units encountering small disturbances (if they're not running VWO), but for a large upset the throttle reserve can be consumed in seconds, returning the unit to slowly working its way toward a 5% droop response. "Governor capability on each resource set with a," should be changed to,"governor set for."

4. BAL-003-3 should explain in the Guidance section that the expression, "set with a droop," in R7 means that the standard addresses only governor settings and not all controls in the plant. That is, removal of DCS overrides causing PFR withdrawal remain a matter of NERC recommendations, but not requirements. This approach is consistent with that of NERC Project 2020-06 (new standard MOD-026-2, replacing MOD-026-1 and MOD-027-1), which in its present draft allows in R3.2, "outer loop controls that override the governor response or modes of operation that limit frequency response," so long as they are represented in the governor model provided to the TP. They could be reported again for BAL-003-3, if NERC prefers, but words cannot describe this phenomenon as well as a mathematical model.

5. BAL-003-3 should explicitly allow droop response limiters for protective purposes. A reduction in grid frequency of 40 mHz (0.0667%), for example, causes a 5% droop unit to try to increase its output power by 1.3% of full load (= 20 x 0.0667). This moderate step-change is achievable by most if not all synchronous generator units, but if frequency suddenly drops by 0.5 Hz (as happened during winter storm Uri) a unit with unrestricted 5% droop would try to immediately jump 16.7% of full-load output (e.g. 125 MW for a 750 MW fossil unit). Many CTGs can do so, subject to the OEM's ramp rate limit and bounded by the firing temperature limit, but such an immediate jump is radically beyond OEMs' recommended ramping rate limits for fossil units, and overriding the OEM's criteria is likely to trip the unit due to drum level fluctuations, duct pressure upsets or other causes (FERC's report indicates there were some such trips during Winter Storm Uri). This is the worst possible response to extreme grid disturbances. Here again the protective settings would be captured in the MOD-026-2 model, and reported also for BAL-003-3 if NERC prefers.

6. BAL-003-3 should change the R7 option of declaring that "the resource as designed does not have frequency response capability," to, "the resource does not normally operate in the frequency-responsive mode." The STG of a 2x1 combined cycle plant should qualify as being unresponsive for BAL-003-3 R7 purposes if running VWO when both CTGs are online, for example, even though it can and will react to frequency disturbances when throttling in the 1x1 mode. Many units that show no PFR could in fact respond if backing-down to create headroom, but BAL-003-3 is not seeking such a move, yet the situation is not really a, "unit as designed," issue.

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	No
Document Name	

Comment

TEM supports the comments of Talen Generation.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	No
Document Name	

Comment	
No, see response to previous question (#2).	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
These issues should be agreement or contract issues between the interconnected generator, and the Balancing Area they are responsible to. With the many types and ages of generation resources, the BA is the most appropriate authority to determine performance required by the GOs and GOPs.	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	
NCPA agrees with and supports the answers of Cogentrix Energy Power Management, LLC & Manitoba Hydro to Question 3. James Mearns, Northern California Power Agency, Segments 3, 4 & 5	
Likes 0	
Dislikes 0	
Response	
David Melanson - NB Power Corporation - 5	
Answer	No
Document Name	

Comment	
If FERC under the Pro Forma Tariff (detailed in FERC Order 842) are requiring a dead-band of 36 mHz and droop of less than 5%, is the duplicative NERC requirement required?	
Likes 0	
Dislikes 0	
Response	

Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
In the proposed requirement R7, LADWP recommends to remove the word “set” (remove bold word): “Each Generator Owner shall have its Governor capability on each resource **set** with a droop of…” Although, it’s acceptable for the standard to require the capability, the Balancing Authority should have the authority on how it orchestrates frequency response. Secondly, R7, first bullet, “… The droop setting is greater than (5) percent or the deadband is greater than 0.036 Hz…” creates confusion by allowing a broad exception, similar to saying, “Each Generator Owner shall have XYZ requirement, unless it does not have XYZ requirement.”	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF agrees with the numerical values specified in R7, offers the following for the SDT consideration: 1. **Clarity on *type* of deadband speed:** There are two types of deadband speed in governing systems: intentional (i.e. settings) and inherent (i.e. hysteresis, control linkage backlash etc). NAGF recommends the SDT clearly articulate in supplementary guidance that, although test reports can be provided as proof of settings, BAL-003-3 R7 is not does not require GO/GOPs to conduct disturbance responses tests to identify the total deadband.	

NAGF Operational Example: Generation units with mechanical-hydraulic controls (MHC) may not have a setting for intentional deadband. BAL-003-3 should state that this falls under the exceptions clause of R7, as opposed to requiring disturbance response testing to identify the inherent deadband value. This is especially the case since, if finding an inherent deadband greater than 36 mHz, there is no means of adjusting it.

2. Technical Guidance Clarification BAL-003-3-R7: BAL-003-3 R7 currently states: Each Generator Owner shall have its **Governor capability on each resource set with a droop** of no more than five (5) percent and a deadband not more than 0.036 Hz. Exceptions to these setting requirements are allowed if the Generator Owner has notified its Balancing Authority that: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]. NAGF recommends that, for absolute clarity, the SDT use the technical rationale or implementation guidance to clearly identify that the standard addresses only governor settings and not total-unit response to disturbances. Removal of DCS overrides causing Primary Frequency Resposne withdrawal remain a matter of NERC recommendations, but not requirements. This approach is consistent with that of NERC Project 2020-06 (new standard MOD-026-2, replacing MOD-026-1 and MOD-027-1), which in its present draft allows in R3.2, "outer loop controls that override the governor response or modes of operation that limit frequency response," so long as they are represented in the governor model provided to the TP. They could be reported again for BAL-003-3, if NERC prefers, but words cannot describe the phenomenon at hand as well as a mathematical model.

3. Allowance of Droop Response Limiters for Protection Purposes: The NAGF recommends the SDT revise BAL-003-3-R7 and / or clearly articulate via techcnial rational or implementation guidance that droop response limiters are allowed for protective purposes. Without a droop response limiter there is the potential that a frequency event on the grid may cause a generator to significantly increase generation which is likely to trip the unit.

NAGF Operational Example: A reduction in grid frequency of 40 mHz (0.0667%), for example, causes a 5% droop unit to try to instantly increase its output power by 1.3% of full load (= 20 x 0.0667). This moderate step-change is achievable by most, if not all, synchronous generator units, but if frequency suddenly drops by 0.5 Hz (as happened during winter storm Uri) a unit with unrestricted 5% droop would try to immediately jump 16.7% of full-load output (e.g. 125 MW for a 750 MW fossil unit). Many CTGs can do so, subject to the OEM's ramp rate limit and bounded by the firing temperature limit, but such a jump is radically beyond OEMs' recommended ramping rate limits for fossil units, and overriding the OEM's criteria is likely to trip the unit due to drum level fluctuations, duct pressure upsets or other causes{C}[1]{C}. This is the worst possible response to extreme grid disturbances, potentially turning survivable events into region-wide blackouts. Here again the protective settings would be captured in the MOD-026-2 model, and reported also for BAL-003-3 if NERC prefers.

4. Allowance for exemption: Like NERC, the NAGF recognizes that our grid is in a state of transformation. Given the diversity of today's generation capabilities and consistent with VAR-002, the NAGF recommends that the SDT clearly articulate in supplemental guidance that exceptions based on capability or other are allowed but that they must be reported to the BA. In addition to entity identified and declared exemptions, the STD may want to consider adding language tht allows the BA to identify exemtions. NAGF populated examples of entities that may request exemption are as follows :

o Entities not applicable to FERC Order 842, which though technically capable of providing frequency support may not have enabled it because it was not required as part of their interconnection

o Other entities as determined by BA; As this standard becomes applicable to generators, there may be some challenges, specifically for intermittent resources which may result in the BA being inundated with notifications. The BA should have the flexibility to exempt (perhaps on an annual basis) certain entities or categories of generators from this standard.

5. Clarity on R7 Exception: Currently BAL-003-3 R7 allows resources that are not designed with frequency response capability to be an exception to the requirement. NAGF suggests that this exception should be re-written as follows: "the resource as designed, **during normal operating mode**, does not have frequency response capability," pertains to the normal operating mode.

NAGF Operational Example: The STG of a 2x1 combined cycle plant is unresponsive for BAL-003-3 purposes if designed to run VWO when both CTGs are online, for example, even though it reacts to frequency disturbances when throttling in the 1x1 mode.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	

A deadband threshold that is too low can create an energy management issue depending on the technology used. In the case of Dispersed Power Producing Resources, the frequency control may have a different deadband threshold on the overfrequency or the underfrequency, so it is more expedient to have a less severe deadband threshold for these resources. A distinction would be relevant.

Eg: for wind power, if too much kinetic energy is sollicited, the generator and a outage could occur. The same for batteries, it would eventually discharge and create unacceptable losses.

For a given droop setting, the governor response will vary according to the base that is used in the governor to convert power from MW to “per unit” value. Also, mechanical and analog governors, even if set to 5% droop, may result in a slightly different response than expected. For this reason, a tolerance (e.g., ±1%) should be allowed to cover these cases.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

The Requirement R6 as drafted appears to apply to generating facilities that are not part of BES (i.e. “… each generating unit/generating facility that is connected to the interconnected transmission system…”).

The Requirement R7 uses the term “resource” to identify the scope of applicability. BC Hydro suggests that consistent language be used in Requirements R6 and R7.

BC Hydro requests that the drafting team clarify the applicability intent and revise the wording of Requirements R6 and R7 as appropriate.

BC Hydro’s understanding is that the intent of Requirement R6 is to mandate that the generating units provide Primary Frequency Response. BC Hydro suggests that it is better to define the status of a Governor, i.e. when a Governor is considered “in-service” and “out-of-service” to help ensure R6 is implemented as intended.

The wording of Requirement R7 could be interpreted to the effect that a Generator Owner may no longer be in compliance once it discovered a setting of the droop and/or deadband outside the R7 specifications. These settings on analog and mechanical governors can drift over time, and this drift can only be discovered during regular maintenance activities or during analysis of actual frequency events.

BC Hydro interpretation of the intent of this new Requirement R7 is that if a setting is identified as requiring any changes during the maintenance activities, then the setting(s) will be corrected without the risk of incurring a possible violation.

BC Hydro suggests that the wording of Requirement R7 be modified to clarify that, similar to Requirement R6, the Generator Owner will remain in compliance with R7 if appropriate notification to the BA is made within certain time from discovery of a setting that is not meeting the droop and/or deadband specifications and a corrective action plan is created.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG concurs with NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	No
Document Name	
Comment	
A deadband threshold that is too low can create an energy management issue depending on the technology used. In the case of Dispersed Power Producing Resources, the frequency control may have a different deadband threshold on the overfrequency or the underfrequency, so it is more expedient to have a less severe deadband threshold for these resources. A distinction would be relevant. Eg: for wind power, if too much kinetic energy is solicited, the generator and an outage could occur. The same for batteries, they would eventually discharge and create unacceptable losses.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	

Comment	
Capital Power supports the submitted NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	No
Document Name	
Comment	
The BA should have the authority to exempt droop and dead-band settings. Examples include, the steam turbine of a combined cycle train that won't be able to provide PFR as when in valves wide open mode, units performing test, or units that have informed the BA of governor control issues that the BA may want online for MW rather than being forced offline to repair governor components.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support adding Requirement R7 for GOs because the BA already has the ability to request this information from their GOs under TOP-003-4 making this new requirement under BAL-003 unnecessary and possibly duplicative of TOP-003-4. EEI notes that Requirement R2 (TOP-003) requires BAs to maintain a documented specification for data necessary for it to perform its analysis functions and Real-time monitoring, while Requirement R5, requires GOs receiving a data specification (under R4) to satisfy the obligations of the documented data specification.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No

Document Name	
Comment	
Southern Company does not support adding proposed Requirement R7 for GOs and supports the comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation has no specific objection, however has raised concerns on if specific generation units will be able to meet the proposed requirements and any exclusionary requirements if unable to meet the specifications in R7. Kimberly Turco, on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation has no specific objection, however has raised concerns on if specific generation units will be able to meet the proposed requirements and any exclusionary requirements if unable to meet the specifications in R7. Kimberly Turco, on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	

Droop and deadband settings requirements are as good as are the values selected. These terms are applied to turbine governors. CHPD suggests using an industry standard term for governor and removing the concept of frequency responsive controls to make this application clear. It is assumed that the requirement intends to specify that if you have a governor, you set the droop and deadband as desired.

Suggest adding "internal memos or other documentation" to the examples of evidence. Many legacy governors have a knob on the front of the cabinet labled droop that sets the droop value. Clarification that a memo when the droop is set at 5% will reduce confusion and questions for those with older governors where there are not "setting sheets" like a modern digital control. Additionally, deadband should be specific to speed deadband as there are other deadband settingswithin a governor. We suggest using the term speed deadband which is defined by IEEE.

Requirement R7 provides an exception "The resource as designed does not have frequency response capability." This introduces a new concept and term. Is the exception intended to exclude any resource that does not have a governor, (small hydro, solor, and wind for example), will not respond to frequency, or does not have a controller that responds to frequency deviations? CHPD requests that this exception be clarified since it is not clear.

Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	

Evergy contends that R7 is unnecessary because the BA already has the capability of requiring Generator Owners to provide this data in their data specification created for TOP-003-4 R2. Allowing the BA to require exactly the data they need as inputs for the processes they put in place to handle frequency response provides much greater flexibility for the BA to meet its frequency response objectives. In addition, there are currently no BAL standards that have GOP/GO applicability and adding those applicable entities to this standard could create confusion when a mechanism to get this data already exists. Adding a requirement for a GO in this standard could create a double jeopardy scenario if a BA already requires the same or similar data be provided under TOP-003-4 R2. Lastly, we do not believe this is an actual problem that needs to be solved. FERC Order 842 clearly requires new generation to incorporate the exact same droop and deadband settings. If BAs are concerned that older generation units are not set to these requirements, they can simply ask the GO for their current settings under TOP-003-4 and have the GO report when those change.

Likes 0	
Dislikes 0	

Response	
Amy Jones - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
Clarification language should be added so that this requirement does not apply to minimal changes, such as changes in the percent of a resource that is pseudo tied from one BA to another. As an alternative, language could be added that this action is not necessary if both BAs agree it is not necessary. Grant PUD believes it is important to weigh the workload involved with the benefit from a requirement that only applies for part of a year.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
The requirement as written does not allow for steam turbine generators in combined cycle operation, which are often operated in inlet pressure or boiler following (in these cases the governor may be in service but set at some high speed). Each “generator” is treated separately as opposed to considering the aggregate droop of the combined cycle “unit”, something that has been discussed and considered allowable in prior papers associated with Primary Frequency Response.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon concurs with the comment posted by EEI for Question 3 On behalf of Exelon, Segments 1 and 3	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports adding Requirement R7, but recommends that the Requirement account for mechanical governor systems where dead band is not tunable to that level.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Yes, GOs should be providing notice to BAs if they are expected to provide FR but are incapable.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	

Comment	
PNM supports adding proposed Requirement R7 to BAL-003.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

This recommendation was part of the NERC guideline and will increase reliability if all generators have to do this.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees with the SDT that these are appropriate minimum settings for governor capability. BPA believes new requirement R7 provides an appropriate exception to notify BAs, if a generator resource is not designed or does not have frequency response capability. BPA notes that this should only be applied to existing plants or other plants, such as nuclear, which may have additional safety reasons for not providing frequency response.	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ISO-NE generally supports the concept of creating a “no more than 5% droop” requirement and a deadband requirement of not more than 0.036 Hz. However, ISO-NE believes any exception to the requirement should be reviewed *and approved* by the BA. As currently written, a GO could simply design its resource to not have frequency response capability and tell its BA, “My unit is exempt from this requirement because, *as designed*, it does not have frequency response capability.” ISO-NE believes the only time a generation unit should receive an exemption from R7 is when it is not technically feasible for the unit to meet the requirement.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	Yes
Document Name	

Comment

BHC follows the WECC Criteria best practices that include Governor droop settings.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

BHC follows the WECC Criteria best practices that include Governor droop settings.

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	Yes
Document Name	

Comment

BHC follows the WECC Criteria best practices that include Governor droop settings.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
BHC follws the WECC criteria best practices that includes Governor Droop settings.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports the proposed Requirement R7.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
This ensures the GO keeps the goverenor within reasonable operation parameters.	

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	Yes
Document Name	

Comment

Per the SRC's response to Question #2, frequency response requirements on GOs and GOPs are critical to ensure adequate frequency response in the interconnections and within each Balancing Authority Area. Setting standards on droop and deadband settings will ensure a coordinated response to frequency disturbances. Absent the requirements on GOPs to provide frequency response, BAs cannot guarantee covering their frequency response obligation.

The SRC also recommends the SDT add a requirement R8 giving BAs the authority to grant an exemption from R7.

Likes 0	
Dislikes 0	

Response

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.

Answer	Yes
Document Name	

Comment

PGE supports this requirement. As this does not (and should not) impose any requirement for the resource to carry any specific headroom, this requirement should not have negative impact on the Generator Operator. It is simply requiring that the frequency response logic already installed be active. However, headroom is always carried somewhere, and in effect this requirement simply states that wherever the headroom happens to be carried, it should be frequency responsive. This requirement is specifically important and timely as the system transitions to an increasing percentage of wind, solar, and battery storage. A common historical assumption is that such resources will never carry headroom, but that has already been proven false, and the amount of headroom carried on these resources will only increase with time. This requirement would ensure that such headroom will be frequency responsive. Without this requirement we could continue to see an influx of non-frequency responsive resources replacing existing frequency responsive resources, similar to the large scale installation of gas plants without properly tuned governor response that lead (in part) to the formation of BAL-003 to begin with.

Likes 0	
Dislikes 0	

Response

Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
AZPS supports the proposed addition of Requirement 7 to BAL-003.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE notes the differences between proposed Reliability Standard BAL-003-3 and Regional Standard BAL-001-TRE-2. Proposed Reliability Standard BAL-003-3 Requirement R7 provides for the GO to notify the BA if the droop setting is greater than five percent or the deadband is greater than 0.036 Hz or the resource as designed does not have frequency response capability. Texas RE Regional Standard BAL-001-TRE-2 Requirement R6 gives the BA the ability to direct the GO Governor parameters with no explicit notification from the GO to the BA required. Texas RE is concerned there is no requirement for the issues occurring in BAL-003-3 Requirement R7, if they exist, to be mitigated. Texas RE recommends there be a requirement for the Governor to be in-service, as well has have specific droop and deadband settings, similar to the Texas RE Regional Standard BAL-001-TRE-2. Texas RE recommends clarifying the language in proposed Reliability Standard BAL-003-3 to state: “Exceptions to these setting requirements are allowed if directed by the BA after the GO notification to the BA of the reasons for inability to meet the settings.” It is simply assumed the Operating Plan would capture the high-level needs of the BA for allowing the different settings.	
Likes 0	
Dislikes 0	

Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT supports the comments filed by the ISO/RTO Council's Standards Review Committee (SRC) and adopts those comments as its own.	
Likes 0	
Dislikes 0	
Response	

4. The SDT has made modifications to the standard to allow the data collection process currently performed through the use of the FRS Form 1 to move to a Section 1600 Data Collection process. This would allow the Balancing Authorities to use their own forms to calculate their performance under Requirement R1 while allowing for the needed data collection through a separate means. Do you agree with this modification to the standard? Please provide the reasoning or justification for your position in the comments.

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the existing process for data collection using the standardized Form 1 for all entities. Allowing an entity to use their own forms for analysis may result in the inconsistent collection and reporting of data and performance metrics.

Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

Perhaps some BAs desire to use or develop their own forms. For us, developing our own forms is not only additional work but introduces the risk of error. Using NERC-developed forms and spreadsheets, while not error free, did provide a level of certainty that we were providing exactly what was requested. It is not clear why this change is desirable.

Likes 0	
Dislikes 0	

Response

Amy Jones - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	No
Document Name	

Comment

Clarification language should be added so that this requirement does not apply to minimal changes, such as changes in the percent of a resource that is pseudo tied from one BA to another. As an alternative, language could be added that this action is not necessary if both BAs agree it is not necessary. Grant PUD believes it is important to weigh the workload involved with the benefit from a requirement that only applies for part of a year.

Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	
While CHPD does not object to moving the required forms outside of the actual Standard, allowing Balancing Authorities and FRSGs to use their own forms could lead to disparate ways of getting to a performance metric.	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
LDWP recommends the current data collection process to remain the same and performed through the use of FRS Form 1. In addition, LDWP strongly agrees and supports American Electric Power's (AEP) comments which state, "AEP recommends against changing to a Section 1600 Data Collection process for the purposes of this standard. Data needs, types, and formats all vary across BAs, as do the terms and definitions used by each. Using a Section 1600 data collection methodology could lead to data confusion and inconsistencies from region to region."	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No

Document Name	
Comment	
NCPA agrees with and supports the answer of AEP to Question 4. James Mearns, Northern California Power Agency, Segments 3, 4 & 5	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Given the complexity of the Forms associated with calculation of the FRM, it is likely that these forms may require a large effort to maintain. The difficulty in maintenance, understandably, leads to some desire to do away with them and simplify the process by requiring BAs to calculate and submit their own FRM values. The problem with this approach is that without a single unifying approach, the calculation processes will likely diverge. This will mean that, though each Interconnection depends on the BAs within it for Frequency Response, there will be varying levels of quality of the measure of that Frequency Response. This uncertainty makes the true available amount of Frequency Response suspect, which is not appropriate for an Essential Reliability Service – particularly one where the under-provision of Frequency Response can lead to severe Reliability problems that can develop and spread at a rate that is potentially faster than human operators can react. Please do not let expediency trump the need for consistent determination of Frequency Response. If maintenance of the forms is problematic, perhaps it would be best to have a third party maintain them.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
It is not clear if this proposal will simplify the reporting process or make it more redundant and inefficient.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Manitoba Hydro supports the existing process for data collection using standardized forms for all entities. Allowing an entity to use their own forms for analysis may result in the inconsistent collection and reporting of data and performance metrics. Furthermore, Canadian entities are not required to submit data under section 1600 data requirements. Please provide clarification on Canadian reporting requirements for this change to the standard.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Will the FRCM be included on the FRS Form 1?	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP recommends against changing to a Section 1600 Data Collection process for the purposes of this standard. Data needs, types, and formats all vary across BAs, as do the terms and definitions used by each. Using a Section 1600 data collection methodology could lead to data confusion and inconsistencies from region to region.	
Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Clarification is needed regarding the data collection process for BAL-003-3, more specifically clarification of acceptable document format to use, to be submitted and timeline of data to be submitted. Additionally, as long as the FRS Form 1 continues to be provided to entities that wish to continue using the form, AZPS supports the use of the data collection process. However, if the FRS Form 1 is no longer provided to entities, there may be risk to differing BA FRM and FB determinations/calculations. Lastly, if a proposed form is drafted, a copy of the form should be provided to entities to allow a review and ability to ask questions and/or provide input.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
PGE agrees with the structural changes to the data collection process, as well as the addition of the FRCM measurement, which will better facilitate comparison of perfommance across multiple compliance years as the FRO changes. The inclusion of the 60 Hz maximum starting point for underfrequency events and minimum for over frequency events is a meaningful improvement, as it more closely aligns with the design and performance of the primary frequency response provided by governor controls that include deadbands per NERC Guidelines. Additionally the clarification of how to handle a single member of an FRSG having bad data for an event is a clear improvement.	
Likes 0	

Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comment posted by EEI for Question 4 On behalf of Exelon, Segments 1 and 3	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
IID supports the existing process for data collection using the standardized Form 1 for all entities. Allowing an entity to use their own forms for analysis may result in the inconsistent collection and reporting of data and performance metrics.	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no proposed comments.	

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation has no proposed comments.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Southern Company supports modifying the standard to allow Balancing Authorities to use their own forms to calculate performance under R1 while allowing for data collection through a separate process.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment	
EEI supports the proposed move from the use of FRS Form 1 to a Section 1600 Data Collection process.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the submitted NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports the proposed use of the Section 1600 Data Collection Process.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	

Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.

Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports the comments of EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
This will relieve the NERC staff of a tremendous amount of paperwork that currently isn't verified on the accuracy of the calculation.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports the comments of NAGF.	

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment

No additional comments

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	Yes
Document Name	

Comment

PNM agrees with this requirement change utilizing a data collection format similar to FRS Form 1.

Likes 0	
Dislikes 0	

Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Yes, as long as Form 1 is still provided to those who wish to use them. Eliminating the FRS Form 1 shifts the onus of understanding and modifying the Form 1 functionality to the BAs, and also increases the likelihood for differing methodologies to proliferate and allowing different BAs to use different methods to calculate the FRM and Bias. This action may be a trigger to compliance for validation.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Melanson - NB Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT supports the comments filed by the ISO/RTO Council's Standards Review Committee (SRC) and adopts those comments as its own.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro suggests that the reference to Section 1600 of NERC Rules of Procedure is not necessary as part of the language of the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	
Document Name	
Comment	
No comment, BHC is not a BA	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	
Comment	
No Comment - BHC is not a BA	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
No Comment - BHC is not a BA.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	

Answer	
Document Name	
Comment	
No Comment - BHC is not a BA	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
Although some may argue that the current method is acceptable and does not need to change, WECC supports whatever method of collecting the data the industry supports.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	
Document Name	
Comment	
No opinion	
Likes 0	
Dislikes 0	
Response	

5. Do you believe that proposed Reliability Standard BAL-003-3 can be met in a cost-effective manner? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification. Please provide the reasoning or justification for your position in the comments.

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
As per the above, the requirements are too vague and trying to accurately forecast the frequency response of load, DERs, units near full output, etc. would be onerous for the BA.	
Likes 0	
Dislikes 0	
Response	

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
There is no recourse for generator to recoup the cost of providing frequency responsive reserves versus other units that are not providing reserves. Market accommodation is needed to provide an equitable platform all generators in terms of frequency response.	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy agrees with MISO's submitted comments for question 5.	
Likes 0	
Dislikes 0	

Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Based on Manitoba Hydro's interpretation, this is not a cost effective plan. Additional costs will be incurred to support our own FRS forms, the new section 1600 data collection process, implementation and maintenance of R5, R6 and R7.	
Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports MISO's comments in response to Question 5.	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
The proposed Standard is unnecessary, as outlined in our previous responses, therefore any costs associated with compliance are wasted. Our recommendation is that the SDT not propose Requirements R5, R6, or R7.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Requiring BAs to implement an Operating Process to ensure adequate frequency response in the Operations Planning timeframe (day-ahead to seasonal) would require significant changes to existing operational planning processes. To MRO NSRF's knowledge, many BAs have limited capabilities to quantify frequency responsive reserves, at the most frequent, seasonal/ad hoc studies. This is due to the complex nature of the resource models used to quantify frequency responsive reserves and would pose a significant challenge as there is currently no accurate representation of generators' capabilities and performance. Moreover, a day ahead process would also need to be established between the BA and the GOPs to obtain governor availability. In short, implementation would be very burdensome and again, not worth the expected reliability benefit. **The MRO NSRF proposes the SDT consider lower cost alternatives**. For example, the SDT could address the issue described under Question 1 by raising the measure from "median." This would raise the bar of reliability performance without requiring any entities to incur additional cost. As currently the Annual Frequency Response Measure and Frequency Response Compliance Measure for the Operating Year are determined by taking the median of the individual event FRM and FRCM values, respectively. (see page 20 of 24)	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
The proposed changes of BAL-003 shift compliance burden to GO/GOPs and create administrative burden not related to reliability. The changes may not be viewed as major by the drafting team, but the addtional compliance burden and risk is not in line with the benefit.	
Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
R5 adds significant effort and work product without adding more than a possibility of minimal value. R5 should be changed to a performance metric or removed.	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	

NCPA agrees with and supports the responses of Cogentrix Energy Power Management, LLC & MRO NSRF to Question 5.

James Mearns, Northern California Power Agency, Segments 3, 4 & 5

Likes 0	
Dislikes 0	

Response

David Melanson - NB Power Corporation - 5

Answer	No
Document Name	

Comment

As per the above, the requirements are too vague and trying to accurately forecast the frequency response of load, DERs, units near full output, etc. would be onerous for the BA.

Likes 0	
Dislikes 0	

Response

Glenn Barry - Los Angeles Department of Water and Power - 5

Answer	No
Document Name	

Comment

For the standard to be implemented in a cost-effective manner, the proposed edits to the standard should increase relibiality of the power system. The proposed new requirements will require additional staff and resources and LADWP does not believe it increases realibility.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

R7 seems to be the requirement engaging the greaters costs. The resource settings (droop and deadband) could be instructed or determined by the BA Area in which the generating facility is in.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG concurs with NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	No
Document Name	
Comment	
R7 seems to be the requirement engaging the greater costs. The resource settings (droop and deadband) could be instructed or determined by the BA Area in which the generating facility is.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

Constellation requires further evaluation before providing comments on the cost-effectiveness for specific generation facilities, especially Nuclear Facilities and Inverter Based Resources and the ability to meet the outlined requirements proposed in R7.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation requires further evaluation before providing comments on the cost-effectiveness for specific generation facilities, especially Nuclear Facilities and Inverter Based Resources and the ability to meet the outlined requirements proposed in R7.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

Implementing proposed requirement R5 would create a burden significantly outweighing the expected reliability benefit. Requiring BAs to implement an Operating Process to ensure adequate frequency response in the Operations Planning timeframe (day-ahead to seasonal) will require significant changes to existing operational planning processes. For example, many BAs have limited capabilities to quantify frequency responsive reserves in the most frequent, seasonal/ad hoc studies, due to the complex nature of the resource models to quantify frequency responsive reserves. This situation poses a significant challenge as there is currently no accurate representation of generators' capabilities and performance. Moreover, BAs and GOPs would have to establish a day ahead process to have GOPs provide governor availability data to the BA.

In contrast, the cost associated with implementing requirements R6 and R7 would be minimal. Following the issuance of FERC Order 842, new generators and generators performing material modifications must install and maintain equipment to control frequency in accordance with their

Interconnection Agreements. Therefore, the additional costs for GO/GOPs to comply with this standard are minimal (although this standard may create minimal maintenance costs to ensure the equipment is configured and operating satisfactorily).

The time horizon for R5 is "Operations Planning" and R5 does not require real-time monitoring. However, if this standard expects BAs to ensure adequate frequency response to continuously meet the Frequency Response Obligation in real time, significant costs will accrue due to redispatching the optimal mix of generation and ensuring adequate head room on generation to provide the required frequency response at all times, in addition to the costs incurred to implement an Operating Process described above. This activity could result in higher dispatch costs for the system as a whole.

The proposed Standard also does not address when the BA falls below its obligation, which may impact costs associated with implementing this standard. The SRC requests the SDT provide additional details regarding the situation when a BA does not meet its obligation so the SRC can assess potential additional costs.

Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	No
Document Name	

Comment

In the webinar it was stated that the requirements are not to retrofit units that were not designed with a governor or can provide frequency support. This should be explicitly stated. Requirement R7 provides an exception if the "resource as designed does not have frequency response capability". This should be included in Requirement R6 for consistency. Also, future units should also be addressed. Are future units or rehabilitated units required to implement frequency responsive controls or governors? This would add cost that may not be effective in supporting system frequency.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the MRO NSRF for question #5.

Likes 0	

Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MEC supports MRO NSRF comments to consider less costly options.	
Likes 0	
Dislikes 0	
Response	
Amy Jones - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
Clarification language should be added so that this requirement does not apply to minimal changes, such as changes in the percent of a resource that is pseudo tied from one BA to another. As an alternative, language could be added that this action is not necessary if both BAs agree it is not necessary. Grant PUD believes it is important to weigh the workload involved with the benefit from a requirement that only applies for part of a year.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Probably but to-be-determined really.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
With the ability to use current tuning data that to demonstrate deadband (0.036 Hz) and no more than 5% droop.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	

Answer	Yes
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports the comments of NAGF.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
As a registered GO/GOP, SIGE is responding to the question based on the applicable GO/GOP requirements (R6 & R7). SIGE believes R6 and R7 can be met in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	

Comment	
Capital Power supports the submitted NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Several processes have been developed for VAR-002 requirements. It would be minimal effort to expand the scope of the processes to include BAL-003 requirements.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company believes the proposed Reliability Standard BAL-003-3 can be met in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes

Document Name	
Comment	
If adjustments as we've suggested are made to R6 and R7, generally the standard is not requiring a lot of cost-intensive work.	
Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5,	

6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	
Estimating the cost effectiveness of the proposed BAL-003-3 is not straightforward.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	
BHC is not a BA. As a Generator Owner, BHC cannot determine cost effectiveness and will not provide an opinion.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC is not a BA. As a Generator Owner, BHC cannot determine cost effectiveness and will not provide an opinion.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	

Answer	
Document Name	
Comment	
BHC is not a BA. As a Generator Owner, BHC cannot determine cost effectiveness and will not provide an opinion.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 1,3,5,6	
Answer	
Document Name	
Comment	
BHC is not a BA. As a Generator Owner, BHC cannot determine cost effectiveness and will not provide an opinion.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
Pending additional clarifications per BC Hydro's comments under Questions 2 and 3 of this survey, BC Hydro is unable to answer this Question at this time.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT supports the comments filed by the ISO/RTO Council’s Standards Review Committee (SRC) and adopts those comments as its own.	
Likes 0	
Dislikes 0	
Response	

6. Do you have any comments on the modified Violation Severity Level (VSL) for Requirement R1, or for the Violation Risk Factors/VSLs for proposed Requirements R5, R6, and R7?

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Consistent with our proposal above to separate R6 into two obligations, the VSL should also be separated and appropriately aligned.	
Likes 0	
Dislikes 0	
Response	

Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the submitted NAGF comments.	
Likes 0	
Dislikes 0	
Response	

David Melanson - NB Power Corporation - 5	
Answer	No
Document Name	
Comment	
The requirements must be clarified before VSLs can be adequately commented on.	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
Failure in an admisitrative process of approving and signing a plan annually is not a reliability issue. Auditors will also begin to develop what they "deem appropriate" in an Operating Plan and will find Potential Violations because they feel the plan is not sufficient. This is a bad requirement and NERC has been trying to move away from these types of requirments for some time. Requirements should be performance based, not administrative.	
Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA has no issues pertaining to the VSL for R1 or the VSL/VRF for R5. However, BPA supports the comments submitted by the U.S. Bureau of Reclamation for R6 and R7.	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy's preference is that the BAL-003 VSLs align with the VSLs assigned to MOD-027 and MOD-032.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports the comments of NAGF.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No

Document Name	
Comment	

Reclamation recommends the units of measure in Requirement R1 align with the units of measure in the VSL for R1, i.e., “1” or “100%,” not a mixture of both.

As stated in the response to Question 1, the VSL for Requirement R5 does not ensure reliability. A general Operating Process, as defined in the NERC Glossary of Terms, will not address the target concern. Reclamation recommends the VSL criteria evaluate the effectiveness of the entity’s Operating Process to ensure that the appropriate performance targets are met and maintained.

Reclamation recommends the SDT develop a complete progression of VSLs for Requirement R6 from lower through severe.

Reclamation recommends the SDT develop a complete progression of VSLs for Requirement R7 from lower through severe.

Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	
Comment	

no comment. see question 1.

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	
Comment	

FirstEnergy support EEI’s comments, which state:

Consistent with our proposal above to separate R6 into two obligations, the VSL should also be separated and appropriately aligned.

Likes 0	
Dislikes 0	

Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
The requirements must be clarified before VSLs can be adequately commented on.	
Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Jones - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Scott Kinney - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	

As the proposed R7's violation Risk Factor is currently written as Medium and is in the Operations Planning time horizon, plans from day ahead up to and including seasonal plans would allow entities time to mitigate a violation. Therefore, SDT should consider shifting R7's VSL's:

Currently as written R7 VSL Levels:

- • "High VSL": The Generator Owner operated its Governor with droop and/or deadband settings outside those specified and did not notify the Balancing Authority.
- • "Severe VSL": The Generator Owner does not have documented Governor settings.

Proposed revision R7 VSL Levels to:

- • "Moderate VSL": The Generator Owner operated its Governor with droop and/or deadband settings outside those specified and did not notify the Balancing Authority.
- • "High VSL": The Generator Owner does not have documented Governor settings.

Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	

IID believes R6 should have a Moderate VSL.

Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company supports comments by EEI to separate the VSL and appropriately align with the separation of R6 into two obligations.

Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	

SIGE agrees with the R1, R5, and R7 VSL; however, SIGE recommends modifying the VSL for BAL-003 R6 to align with the BAL-001-TRE-2 R8 VSL as BAL-001-TRE-2 language was referenced for this requirement.

- **Lower:** The Generator Operator notified the Balancing Authority of a change in Governor status between 31 minutes and one hour after the General Operator discovered Governor status change per R6.
- **Moderate:** The Generator Operator notified the Balancing Authority of a change in Governor status more than 1 hour but within 4 hours after the General Operator discovered Governor status change per R6.
- **High:** The Generator Operator notified the Balancing Authority of a change in Governor status more than 4 hour but within 24 hours after the General Operator discovered Governor status change per R6.
- **Severe:** The Generator Operator notified the Balancing Authority of a change in Governor status within 24 hours after the General Operator discovered Governor status change per R6.

Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	

For R7, the following case should be “Lower VSL” instead of “High VSL”, as violation for only one Generator Unit has minor impact on the grid: “The Generator Owner operated its Governor with droop and/or deadband settings outside those specified and did not notify the Balancing Authority.”

Likes 0	
Dislikes 0	

Response

James Mearns - James Mearns On Behalf of: Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ

Answer	Yes
Document Name	

Comment

NCPA supports the response of the US Bureau of Reclamation to Question 6.

James Mearns, Northern California Power Agency, Segments 3, 4 & 5

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

The VRFs and VSLs for Requirements R5, R6, and R7 should be struck along with those proposed Requirements.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	Yes
Document Name	

Comment

For R7, the following case should be “Lower VSL” instead of “High VSL”, as violation for only one Generator Unit has minor impact on the grid: “The Generator Owner operated its Governor with droop and/or deadband settings outside those specified and did not notify the Balancing Authority.”

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

AEP disagrees with R6 being *only* in the Severe VSL category, and recommends it instead be spread across both the High and Severe categories. This should be done driven by the differentiation of whether the required notification was or was-not made within the 30 minute limitation.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	Yes
Document Name	

Comment

The thresholds seem fine but the language “less than 100% by at most x%” is cumbersome at best and confusing at worst. For example:

.85<FRCM<1

.70<FRCM<.85

FRCM<.55

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	

Document Name	
Comment	

Constellation has no proposed comments.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	
Document Name	
Comment	

Constellation has no proposed comments.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	
Comment	

ERCOT supports the comments filed by the ISO/RTO Council's Standards Review Committee (SRC) and adopts those comments as its own.

Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6

Answer	

Document Name	
Comment	
BHC has no comment	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	
Document Name	
Comment	
BHC has no comment.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
BHC has no comment.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	
Comment	

BHC has no comment.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
The MRO NSRF cannot evaluate at this time.	
Likes 0	
Dislikes 0	
Response	

7. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP does not believe that 12 months is adequate to become fully compliant with R7 as this would involve planned outages and associated testing measures (the latter driven by R7's associated measures). For example, if a unit were identified which required modification to enable governor control, significant time may be required to accomplish the engineering and design, to purchase the necessary equipment, and to make the resulting modifications. As a result, AEP recommends that the proposed implementation period be changed to 36 months.	
Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Keep the implementation plan in abeyance until the requirements are clarified.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
The standard contains new requirements and newly applicable functions. Entities that have not had to comply with BAL-003 need time to prepare and adjust their compliance programs and implement the new requirements. Therefore, Reclamation recommends the standard and new/revised definitions become effective 60 months after approval using a phased-in implementation approach similar to MOD-026 and MOD-027.	

Likes 1	Seattle City Light, 4, Li Hao
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments provided for this project

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports the comments of NAGF.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	No
Document Name	

Comment

Entergy agrees with MISO's submitted comments for question 7.

Likes 0	
Dislikes 0	

Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
For the R7 implementation plan; The governor droop settings and dead band value confirmations and evidence may take a longer time to obtain depending on the type of evidence and it is required for each unit or one unit for each plant. For the R6 implementation plan: the implementation plan will depend on the scope of this requirement. Does it only apply to reserve generation resources or does it apply to all generation resources?	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that an abbreviated 12-month implementation may be too constrained. BPA recommends a longer, phased-in approach, to allow Generator Owners and Operators time to stand up their reliability practices and compliance programs.	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports MISO's comments in response to Question 7.	

Likes 0	
Dislikes 0	
Response	
Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments of EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The droop value of an STG with MHC is changed via making front standard adjustments, so time must be allowed for such units to reach their next scheduled overhaul.	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
TEM suuports the comments of Talen Generation.	
Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
As noted in our response to Question 5, the proposed requirements entail significant changes and substantial investment on the part of the BA and GOP to implement this standard. When considering the breadth and depth of the changes needed to accurately model generators' capabilities and performance and the collaboration time needed to work with the Generator Owners and Generator Operators to determine how best to accomplish this, the MRO NSRF recommends an implementation timeframe of 3-5 years, particularly in light of supply chain challenges associated with procuring new software/hardware (CIP-013).	
Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	No
Document Name	
Comment	
Generator Owners will need addtional time, budget, and in many cases, have to engage in a consultant to meet their obligations under the proposed standard. 18 months is more appropriate to GOs who have never had obligations under a BAL standard.	

Likes 0	
Dislikes 0	

Response

James Mearns - James Mearns On Behalf of: Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ

Answer	No
Document Name	

Comment

NCPA agrees with and supports the response of MRO NSRF to Question 7.

James Mearns, Northern California Power Agency, Segments 3, 4 & 5

Likes 0	
Dislikes 0	

Response

David Melanson - NB Power Corporation - 5

Answer	No
Document Name	

Comment

Keep the implementation plan in abeyance until the requirements are clarified.

Likes 0	
Dislikes 0	

Response

Glenn Barry - Los Angeles Department of Water and Power - 5

Answer	No
Document Name	

Comment

As referenced in Q5 these new requirements will require additional resources, staff, and time to meet compliance, therefore LDWP recommends an implementation period of 36 months.

Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
NAGF supports the principles of this standard. However, given that this is a new requirement for generators there will be some preparation required to ensure that changes do not negatively impact the assets and / or grid reliability. NAGF appreciates the SDT consideration of potential outage, operational and budget cycles in the determination of the implementation plan for this standard.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the submitted NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation has concerns on a one year implementation time frame to specified requirements to governor settings. In order to make changes at certain generation facilities a lead time of at least 36 months is required. Constellation asks for a 36 month implementation consideration in regards to setting requirements.	

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation has concerns on a one year implementation time frame to specified requirements to governor settings. In order to make changes at certain generation facilities a lead time of at least 36 months is required. Constellation asks for a 36 month implementation consideration in regards to setting requirements.

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

As noted in our response to Question 5, proposed requirement R5 entails significant changes and substantial investment on the part of the BA and GOP. When considering the breadth and depth of the changes to accurately model generators' capabilities and performance and the collaboration needed to work with the GOs and GOPs to determine how best to accomplish these requirements, the SRC recommends an implementation timeframe of 3-5 years, particularly in light of supply chain challenges associated with procuring new software/hardware (CIP-013).

In contrast, if R5 is stricken, the Implementation Plan for R6 and R7 should be adequate.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the MRO NSRF to question #7.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MEC supports MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Amy Jones - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	

Comment	
No comments on the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM agrees with the proposed implementation plan.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

No additional information

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
From a monitoring perspective WECC has no issue with the proposed Implementation Plan. WECC will respect whatever is approved by the industry.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
As defined and with ‘exception statement bullet left in for R7 for resources that can not or do not have FR, then BHC agrees with the proposed implementation.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

As defined and with ‘exception statement bullet left in for R7 for resources that can not or do not have FR, then BHC agrees with the proposed implementation.

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	Yes
Document Name	

Comment

As defined and with ‘exception statement bullet left in for R7 for resources that can not or do not have FR, then BHC agrees with the proposed implementation.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 1,3,5,6

Answer	Yes
Document Name	

Comment

As defined and with ‘exception statement bullet left in for R7 for resources that can not or do not have FR, then BHC agrees with the proposed implementation.

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

SIGE supports the proposed Implementation Plan.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI supports the proposed Implementation Plan as proposed.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Southern Company agrees with the proposed Implementation Plan.

Likes 0	
Dislikes 0	

Response

Jessica Lopez - APS - Arizona Public Service Co. - 3

Answer	Yes
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Israel Perez - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5,

6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	
The "Timeline for BA FR and FBS Activities" is unclear: when does the ERO actually post the FBS values? What does "…determines implementation schedule for changes to BAs FBS" mean?	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
Compliance with R7 will need to be coordinated with planned outages so testing can be performed and any found concerns can be resolved to satisfy the specified parameters. As such, it is expected that implementation will take longer than 12 months to implement. Depending on the answers to BC Hydro's Questions 2 and 3, BC Hydro would be in a better position to suggest an alternative timeline for implementation once clarifications are provided. A (5-year) phased implementation plan could be more suitable.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Since Requirements R1 and R5 are periodic requirements (annual), Texas RE recommends including an initial performance date so it is clear when the first date needs to be established.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT supports the comments filed by the ISO/RTO Council's Standards Review Committee (SRC) and adopts those comments as its own.	
Likes 0	
Dislikes 0	
Response	

8. Please provide any other comments or feedback, which you haven't already provided, to the SDT related to the proposed modifications to the standard.

Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
MEC supports MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	
Document Name	
Comment	

The SRC supports retaining R6 and R7 and removing R5 as unnecessary. As noted in SRC's response to Q1, SRC recommends the SDT focus on addressing the concerns outlined in the White Paper:

Page 2: Address response from resources. GOPs should be assigned responsibility for provision of tangible generator governor response; and

Page 7: Introduce new GO/GOP requirements to require a GO/GOP to explicitly document and communicate Frequency Response capability, develop methods to explicitly monitor and communicate Frequency Response capability in Real-time, and demonstrate authenticated Frequency Response performance after-the-fact.

Should R5 be retained, R5, R6 and R7 must be retained as a package. Absent R6 and R7, a BA cannot accurately develop an Operating Plan to ensure adequate frequency response because the BA would have no way to know which generators will provide frequency response in Real-time following a disturbance. This fact would make any Operating Plan for frequency response an estimate, at best, and not provide any additional benefit to reliability. As a result, if R5 is not removed, R6 and R7 must remain.

The SDT should clarify the expectation of the Operating Plan in R5. While that requirement applies in the Operation Planning time horizon, the proposed Operating Plan cannot ensure the BA meets its frequency response obligation without monitoring the actual frequency response in real time. A BA can develop a plan but, absent real time monitoring, the BA cannot ensure the plan effectively accomplishes its goal. In addition, the SRC requests the SDT provide guidance on M5 (third bullet) regarding how responsible entities can determine available frequency response in an Operating Plan meets frequency response obligation given real-time operating conditions.

The SRC is also concerned about the language in paragraph 1 of Table 1 (regarding the CLR adjustment). The SRC believes item 1.4 requires revision or clarification. Specifically, item 1.4 provides a load reduction credit so long as the load reduction program is, "[e]xclusively reserved for Frequency Response during normal operations and does not participate in UFLS, Undervoltage Load Shedding (UVLS), or any other Ancillary Service, such as Contingency Reserve, and is not used for any other operator-initiated normal operations." The SRC believes this language intends to ensure the load reduction program, first and foremost, is available for frequency response per the criteria specified in sections 1.1 through 1.3. The SRC agrees with that goal, however, suggests the following clarification for section 1.4:

1.4 Is, during normal operations, exclusively reserved for Frequency Response and not included in UFLS, Undervoltage Load Shedding (UVLS), any other Ancillary Service, such as Contingency Reserve, or any other operator-initiated normal operations;

Making this change makes it clear any load program that can meet 1.1 through 1.5 during normal operations can be counted toward CLR.

Given the comments above, the SRC supports the removal of R5 and the retention of requirements R6 and R7 given the reliability need of frequency response, especially with the increase in variable resources and changing resource mix.

The SRC wants to thank the Standard Drafting Team and supporting roles of this Project. Your hard work and dedication to this Project is sincerely appreciated.

Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no additional comments

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation has no additional comments

Kimberly Turco, on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	
Document Name	

Comment

No further comments by Southern Company.

Likes 0	
Dislikes 0	

Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	

Generator Operators and Generator Owners in the Texas RE region are subject to the requirements of BAL-001-TRE-2, which are more prescriptive. For instance, specific exemptions in BAL-001-TRE-2 are not included in the proposed BAL-003.

- Generating units/generating facilities while operating in synchronous condenser mode are exempt from Standard BAL-001-TRE-2.
- Requirements R6.1, R6.2, and R6.3 are not applicable to steam turbine(s) of a combined cycle resource.

It is problematic for GOs and GOPs in the Texas RE region to be subject to duplicative and/or potentially conflicting requirements. Section 4. Applicablility of BAL-003-3 should include an exemption for GOs and GOPs subject to BAL-001-TRE-2.

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

In the evidence retention section(C.1.1.2) on page 7, the retention period for R1-R5 is “for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation”. The retention period for R6 is stated as “the current and previous calendar years”. Should the retention period for R6 also be limited to the previous three calendar years, unless directed by the CEA to retain for a longer period? The proposed retention period for R7 is not time bound. Should the GO retain evidence for its “current settings” only? Should the GO also retain evidence for any notifications provided to the BA pursuant to R7 for a period of time?

In Attachment A on page 19, there is an allowance for excluding the event if the BA’s tie-line data or Frequency data was corrupt. It would be better if the standard gave some level of guidance to BAs as to what level of missing data is acceptable, similar to what is done in BAL-001-2 for CPS1 data. The current draft language could potentially allow a BA to selectively exclude an event with poor performance even though it only has minor data quality issues that do not have a material impact on its ability to measure the event.

In Attachment A on page 18, the term “Net Interchange Actual (N lower case AI)” is used. Was this intended to be “Net Actual Interchange” as defined in the NERC Glossary of Terms? The term “Net Actual Interchange (NA lowercase I)” is used in the currently effective BAL-003-2, Attachment A. “I lower case NA” might be a better abbreviation since Interchange is the primary subject of the term.

Likes 0	
Dislikes 0	

Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	
Document Name	
Comment	
BAL-001-TRE-2 addresses the steam turbine issues (good approach to follow, for example)	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	
Capital Power supports the submitted NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	
Error on pages 18 of 24. The second bullet under "Single Event Frequency Response Data should be Net Actual Interchange. Clarification is needed regarding the usage of the term "interconnection", (3rd bullet under "Single Event Frequency Response Data, 3rd bullet from the top of page 19. Should it be Interconnection with a capital I as is the case on page 24?	

Section C. Compliance, sub-section 1.2 Evidence Retention: There should be a more specific time period where the Generator Operator shall keep its evidence of notifications. Maybe five (5) years?

Comments on R6**:** Redundancy, Governor should be mentioned only once.

Also, for an “interconnected transmission system”, transmission and system should be capitalized. The word “interconnected” would be then redundant and the sentence would be clearer.

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT supports the comments filed by the ISO/RTO Council’s Standards Review Committee (SRC) and adopts those comments as its own.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG concurs with NPCC RSC.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	

Document Name	
Comment	

Texas RE noticed there is a proposed definition in the standard for Primary Frequency Response. The implementation plan, however, has a proposed definition for Resource Primary Frequency Response. The definitions of both terms appear to be identical. The standard verbiage itself uses the term Frequency Response. The Effective Date section of the implementation plan uses the term Resource Primary Frequency Response. Is this intended to be Primary Frequency Response or Resource Primary Frequency Response? Texas RE recommends using consistent terms throughout the standard and the implementation plan.

Additionally, Texas RE noticed Requirement R7 and Measure M7 have no timeframe associated with the evidence of compliance. Texas RE assumes it is perpetual.

Texas RE has the following recommendations regarding Attachment A:

- Include the equation for calculation of FRM in addition to the text description that is there.
- Consider using a rolling average of the FRM for the most recent events (8-12 minimum), rather than waiting an entire year before calculating the FRM. This would be a better indication of trends in FRM. The number of events will be variable from year-to-year, and there may be some years where there are an insufficient number of events for a statistically valid sample, requiring events from prior years to be included.

Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	
Document Name	
Comment	

1. Error on page 18 of 24. Second bullet under “Single Event Frequency Response Data should be Net Actual Interchange.

2. Clarifivcation needed regarding the usage of the term “interconnection”, (3rd bullet under “Single Event Frequency Response Data, 3rd bullet from the top of page 19. Should it be Interconnection with a capital I as is the case on page 24?

3. Section C. Compliance , sub-section 1.2 Evidence Retention : There should be a more specific time period where the Generator Operator shall keep its evidence of notifications. Maybe five (5) years?

4. Comments on R6 **:** Redundancy, Governor should be mentioned only once.

Also, for “interconnected transmission system”, transmission and system should be capitalized. The word “interconnected” would be then redundant and the sentence would be clearer.

Likes 0	
Dislikes 0	

Response

David Melanson - NB Power Corporation - 5

Answer	
Document Name	

Comment

Refer also to the comments of ISO-NE, PJM, IESO, and NYISO.

Likes 0	
Dislikes 0	

Response

James Mearns - James Mearns On Behalf of: Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ

Answer	
Document Name	

Comment

NCPA agrees with and supports the response of PPL NERC Registered Affiliates to Question 8.

James Mearns, Northern California Power Agency, Segments 3, 4 & 5

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 6

Answer	
Document Name	

Comment

Clarification language should be added so that this requirement does not apply to minimal changes, such as changes in the percent of a resource that is pseudo tied from one BA to another. As an alternative, language could be added that this action is not necessary if both BAs agree it is not necessary. It is important to weigh the workload involved with the benefit from a requirement that only applies for part of a year.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	
Comment	
1) What does the word "annual" mean? Perhaps this should be defined. 2) In the draft standard, there are multiple instances where the term "Balancing Authority" is used, where it would likely be more appropriate to use "Responsible Entity" 3) Will the inclusion of "Primary Frequency Response" in the NERC Glossary of Terms create conflicts or confusion given that the Glossary of Terms already has a definition of "Frequency Response" 4) The Purpose section is unclear: what does "To ensure sufficient FR within the Interconnection within predefined bounds by arresting frequency deviations…" mean? 5) Should Frequency Response Compliance Measure be included in the NERC Glossary of Terms? 6) in R5: What is meant by "…determine its Frequency Response requirements…"? 7) In attachment A: Does the requirement that "For each of these adjustments, a given adjustment must be made for either all events or none of the events in an evaluation year" mean that if a pump load operates during one event it must be evaluated in every event, even if it only operated during one event?	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	
Document Name	
Comment	

This standard strays from holding the BA accountable for it's performance, and places burdens on the GO/GOPs. BAs have an obligation to ensure the generation within their area performs as required to ensure BA performance. Typically this is done through interconnection agreements or contracts. This modification removes the fexibilty in this process, creates addtional compliance burden to GO/GOPs and fails to hold the BA accountable.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

Concern for Double Jeopardy in the TRE Region. The MRO NSRF would like to point out that Generator Owners/Operators subject to NERC Reliability Standard BAL-001-TRE-1 & 2 — Primary Frequency Response in the ERCOT Region (NERC BAL-001-TRE) would be subject to 'double jeopardy' as it relates to proposed NERC Reliability Standard BAL-003-3 – Frequency Response and Frequency Bias Setting, Requirement R6 & R7. Please be aware that the SAR for Project 2017-01 Modifications to BAL-003 - Phase II does identify NERC BAL-001-TRE as a related standard whose impacts need to be considered. The MRO NSRF suggests section §4. Applicability be modified to exempt Generator Owners/Operators subject to the requirements of NERC BAL-001-TRE. Please see NERC BAL-001-TRE for an example.

The MRO NSRF recommends protective language be added under Section 4.2 to clarify the requirements do not require retroactive Primary Frequency Response to be installed.

4.2 Exemptions:

4.2.1 Existing generating facilities not subject to FERC Order 8421
4.2.2 Generating facilities subject to the requirements of NERC Reliability Standard BAL-001-TRE-1 & 2 — Primary Frequency Response in the ERCOT Region

1 https://www.ferc.gov/sites/default/files/2020-06/Order-842.pdf

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	
Document Name	

Comment

We are in support of changes to the Reliability Standard that improve efficiency, such as the change in the Form 1 and mechanism for requesting data. However, we do not support creating additional compliance burden when the need to do so simply has not been demonstrated. Requirements R5 is too vague to be effective or be confidently complied with, and Requirement R5, R6, and R7 are unnecessary in their entirety.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

Will the IFRO values be updated on a yearly basis? If not, the values in the table will go stale potentially before the standard even becomes effective.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment

Please consider additional updates to section C. Compliance to make it conform to the most recent NERC wording for section C. Compliance. Please consider including the abbreviation for "Compliance Enforcement Authority" (CEA) in section 1.1 and using the CEA abbreviation in section 1.2..

Please consider if Generator Owner / Generator Operator requirements should be included in the (BAL) Resource and Demand Balancing family of standards or if another family of standards should be considered for Generator Owner / Generator Operator requirement(s) that are determined to be necessary.

Please consider splitting Requirement R5 into two requirements: A requirement to develop and implement an Operating Process and a separate requirement to annually review and approve the Operating Process. This would allow a different Violation Risk Factor for the annual review, such as a medium violation risk factor, instead of a high violation risk factor. Alternately, please consider if "review and maintain annually" is an administrative requirement that could be removed from R5.

Likes 0	
Dislikes 0	

Response

Joe Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment

Xcel Energy supports the comments of EEI and the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA supports the proposed definitions of ‘Governor’ and ‘Primary Frequency Response’ in the NERC Glossary of Terms. Additionally, BPA thanks the Project 2017-01 Standard Drafting Team for working through these complex issues and drafting meaningful revisions to BAL-003.

Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
None at this time.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
Error on page 18 of 24. Second bullet under “Single Event Frequency Response Data should be Net Actual Interchange. Clarifivcation needed regarding the usage of the term “interconnection”, (3rd bullet under “Single Event Frequency Response Data, 3rd bullet from the top of page 19. Should it be Interconnection with a capital I as is the case on page 24? Section C. Compliance , sub-section 1.2 Evidence Retention : There should be a more specific time period where the Generator Operator shall keep its evidence of notifications. Maybe five (5) years? Comments on R6 **:** Redundancy, Governor should be mentioned only once. Also, for “interconnected transmission system”, transmission and system should be capitalized. The word “interconnected” would be then redundant and the sentence would be clearer.	
Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	
Document Name	

Comment

Entergy proposes that the SDT consider expanding the R6 and R7 language to address exclusions based on regulatory and equipment requirements (for example, Nuclear powerplant output is limited by the licensure requirements of the Nuclear Regulatory Commission).

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	
Document Name	

Comment

Is it possible to move the definition of FRCM into the standard instead of in the Attachment A.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional information	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	
Document Name	
Comment	
Refer also to the comments of ISO-NE, PJM, IESO, and NYISO.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	

Document Name	
Comment	
The proposed standard is largely duplicative of the regional BAL-001-TRE standard currently under enforcement. If the proposed revisions are accepted by industry and formally adopted, does the SDT anticipate the subsequent retirement of BAL-001-TRE?	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	
Document Name	
Comment	
Good revision on moving to a normalized compliance measure which allows for mid year BAA boundary modifications.	
Likes 0	
Dislikes 0	
Response	