Name (9 Responses)
Organization (9 Responses)
Group Name (6 Responses)
Lead Contact (6 Responses)
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Question 1 (0 Responses)
Question 1 Comments (15 Responses)

Individual
Don Tench on Behalf of ENBALA
ENBALA Power Networks
I. INTRODUCTION ENBALA Power Networks (ENBALA) respectfully submits these comments in response to the North American Electric Reliability Corporation (NERC) Technical Conference on Frequency Response held in Arlington VA on May 22, 2012 and Denver CO on May 24, 2012. ENBALA rewards large electricity users for participation in the Smart Grid. The ENBALA Power Network enables industrial, commercial and municipal partners to be financially rewarded for the inherent flexibility of their electrical equipment. Resource partners incur no cost in connecting to this platform and receive payments for helping to bring continuous balance to the electricity system. The purpose of these conferences was to provide background on the development, and implementation of BAL-003-1 - Frequency Response Standard (FRS) and to explain the rationale and considerations for the Requirements and their associated compliance information as well as to solicit feedback from industry participants on the standard. ENBALA provides these comments in support of draft standard BAL-003-1 II. BACKGROUND The requirement to continuously balance load and generation to maintain stable frequency is a critically important aspect of interconnected power system operation. Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections that reacts or responds to changes in load-resource balance and resulting changes in system frequency. Primary Frequency Control is defined by NERC as those actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations, typically caused by a significant system loss. Primary Control comes from mechanical inertia, followed by automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems. Primary Frequency Response (PFR) is the first stage of overall frequency control and is the response, which begins immediately, of resources and load to a locally sensed change in frequency to arrest that change in frequency. This is distinct from Secondary Frequency Control, defined to be those actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from automated dispatch from a centralized control system. The original Standards Authorization Request (SAR) to establish mandatory standards with respect to this critical requirement were established in BAL-003-0, finalized on June 30, 2007. In Order No. 693, the Federal Energy Regulatory Commission (FERC) directed additional changes to this standard . We interpret the objective of the FERC direction to be to establish concrete measures and allocation of Interconnection Frequency Response to ensure continued reliable operation III. COMMENTS Presentations and discussion at the conference provided the following understanding; - The system currently has enough PFR to operate reliably. The concern is that continuing decline could result in unreliability at a future date. The immediate concern is to ensure that the decline on the Eastern Interconnection is halted. - Approximately 30% of generators provide governor response and hence primary frequency control at any time in the Eastern and Western Interconnections. - Primary Frequency Response (PFR) should not be viewed as event driven but rather as continuous control. - The draft standard has been written to give the Balancing Authority (BA) responsibility to meet the standard. The main issue with this is a concern that BA's are being given responsibility but do not have the requisite authority to impose requirements on participants (eg. generators) to provide the PFR. The discussion at the conference focused almost exclusively on the ability of generators to supply PFR through governor action. This is not surprising given the fact that the interconnected power system is based on rotating machines (for the most part) and that speed governors are a necessary part of generator control systems and have been providing PFR for many years. However, there is growing evidence that some generation operators prefer not to provide this service as only a fraction of generators actually

provide PFR to the interconnection at any time. Many reasons were discussed that generators do not provide response, ranging from regulatory restrictions, environmental restrictions, and operation at full output, economic choices to make the plant more efficient, and physical constraints, among others. But in our opinion, all of these reasons come down to a fundamental consideration – the generators must sacrifice some efficiency to provide PFR. This is not a surprising outcome. Prior to electricity deregulation many ‘ancillary services ’ provided by generators were considered to be delivered at low or no cost. However, organized electricity markets have shown that these services have considerable value. Primary Frequency Response is another example. This is not to say that generators may not be the most effective way to provide the majority of PFR. However, generation resources may not be the least cost supplier of PFR. It is important to recognize that this service has a cost and different technologies are able to provide the service at different costs. These costs vary even amongst generation technologies. In addition, there are alternatives to providing all PFR from generation. ENBALA’s experience in providing Secondary Frequency Control (SFC) to organized markets has shown that aggregated mid-sized commercial and industrial facilities can provide very high quality SFC, demonstrably better performance than the majority of generation. This technology can be extended to provide localized PFR as well. It is our opinion that PFR from load can be of higher ‘quality’ than that provided by generation. The ability of individual aggregated loads to increase or decrease nearly instantaneously in response to frequency provides an immediate stabilizing influence on frequency that works together with generator inertia to arrest frequency deviations more quickly than generation alone. Recent studies by California ISO identify that this response can be several times more valuable than slower generation response. Given the facts that; PFR is a valuable reliability service, the cost of providing PFR varies with technology, decisions must be made with respect to who will provide PFR, and alternatives exist to continuing with the provision of generator only PFR, we respectfully make the following suggestions; - The standard should continue as drafted and not limit the technology to provide PFR (eg. generators only) - PFR should be recognized as a reliability service in the same manner as other ancillary services. - The standard should apply to an entity like the BA, as drafted, that has defined responsibility for balancing load and generation - Mechanisms should be developed to procure PFR sufficient to meet NERC standards, on an economic basis either through market or tariff provisions IV. CONCLUSION It is ENBALA’s belief that unless the value of Primary Frequency Response can be made transparent to the marketplace, efficient alternatives will not be implemented and inefficient decisions with respect to existing technologies will be made leading to higher costs for consumers. Treatment of PFR as a market priced reliability service will allow the industry to determine the most efficient and effective way to provide necessary Frequency Response, independent of changes taking place in the supply mix of generation. Respectfully Submitted,
Individual
Robert Blohm
Keen Resources Asia Ltd.
17-year NERC veteran's, long-standing active FRS drafting team contributor's, ex NERC Standards Committee member's, and Columbia-University-postgraduated statistician's expert comments on "Avoiding a Trifecta of Statistics Errors in the NERC Frequency Response Standard". Please review my 6-slide powerpoint presentation downloadable at http://www.robertblohm.com/3FRSissues.pptx or http://www.robertblohm.com/3FRSissues.ppt and submitted but never posted for inclusion in the technical conference. The last 3 slides highlight the following 3 fundamental statistics errors in the FRS as drafted so far: (1) confusion of (the correct probabilistic measure of "largest contingency" consisting of) "largest event to occur at least as often as once in 10 years" with (the incorrect probabilistic measure of "largest contingency" consisting of) "largest event in the last 10 years" which may be the "largest event to occur at least as often as once in MUCH MORE THAN 10 years"; (2) sampling of frequency responses to events that is not true "random", "unbiased" or "stratified" sampling which requires samples that are distributed unevenly over time just like the population of responses to events is: every month or season of the year cannot be forced to have the same number of samples; otherwise what is being measured is not the population of responses to events, but something else (like responses to regular small operating errors that are the domain of CPS, not the FRS) with a probability density over time in the shape of a flat-top box; (3) use of a median measure of frequency-response performance, which is impossible for 3 reasons: because there is a practical infinity of possible Frequency Responsive Reserve Sharing Groups or overlap regulation arrangements, because use of the median incents the formation of those whose actual provision of

frequency response is over-represented by the median and would in that case deteriorate below the actual minimum amount required for system reliability, and because use of the median disincents the formation of those whose actual provision of of frequency response is under-represented by the median. The first 3 slides clarify the following 3 technical points: (1) the resistance of load to adjust to sudden change in generation output prompts frequency (but not generator output) to change and to thereby involuntarily change the load whose resistance to that adjustment prompts frequency to change even more and only until the sudden generation output change is reversed enough in order first to stop the frequency change and then begin to reverse the frequency change; [The involuntary load response/adjustment provides the energy used by generation inertia to immediately slow down frequency change until frequency response is deployed to stop and begin to reverse the frequency change as illustrated in this 4-slide powerpoint presentation of 4 errors in the Cummings presentation's slide of frequency response http://www.robertblohm.com/CummingsVsIllianLoadResponse.pptx or http://www.robertblohm.com/CummingsVsIllianLoadResponse.ppt . The 2 graphs depicted therein show that load response and inertia are inseparable and provide the entirety of frequency response during more than the initial half of the 5 or 6 second pre-arresting period, and this supports the next slide.] (2) the FRS is a standard for "system" frequency response (the 1st of NERC's 2 glossary definitions of "frequency response"), not for "equipment" frequency response (the 2nd of NERC's 2 glossary definitions of "frequency response"); the FRS is a BA-Response System Operation and Measurement Standard, not a Connection and Maintenance Standard for Individual Pieces of Equipment; in other words, all sharp large-enough tie-line and frequency changes of whatever kind for whatever reason are counted (“summed”) and managed (and included in the probability density curve of frequency events and responses thereto), not just measurements of a construed pure machine response to one single imagined un-overlapped change (shorn of supposed "contaminants" of an idealized "equipment" reality non-existent at actual "system" level); (3) the probability density function of frequency events that are un-uniformly distributed over time governs the FRS and is different from the standard normal distribution of operating errors (that governs CPS) that are evenly distributed over time in a uniform distribution.
Group
Dominion
Connie Lowe
Dominion
Dominion agrees that resources other than generators could supply some limited frequency response, but believe that all resources providing reliability-related services should be subject to applicable NERC reliability standards. We also agree that relationships can exist between reliability and compensation, especially in organized markets. In order for generators to be able to respond to a low frequency event, they would need to operate slightly below their maximum output. The Balancing Authority is the entity best suited to make the determination of how to balance efficiency and reliability. There may be financial consequences for resources that do not meet their assigned schedule and we encourage further discussion of this with NAESB to determine whether this issue might be ripe for discussions and possible solutions from NERC (reliability) and NAESB (commercial/financial). As noted in the Duke presentation, alignment is also needed in the new NERC standards and Glossary of terms (clarification is needed on specific terms used by engineering vs. the Generator Operator) as it pertains to frequency response.
Individual
Terry Bilke
MISO
The standard sets a rational backstop for reliability without forcing undue costs for undefined improvements in reliability. My primary concern is the reliability gap created for variable bias BAs. There is no discernible reason why a variable bias BA should ever have a bias less negative than say 30% of its FRO. The variable bias BA should also have an average annual bias at least 90% of its FRO. This can be managed through the year and still will be well less than the current obligation under BAL-003-0. Since there is no firm technical guidance on how variable bias is to be set, to leave this gap will cause a mass movement of BAs to report as variable bias entities. It will also leave the door open to gaming to artificially improve CPS and DCS and BAAL performance.
Group

SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
Requirement 3 of the standard covers the use of variable bias. However, the requirement does not establish a minimum limit for variable bias. In order to prevent what could be perceived as a way to 'game' the requirement, we would suggest incorporating a minimum limit on variable bias that does not allow the value to be positive.
Individual
John Seelke
Public Service Enterprise Group
PSEG Comments on Project 2007-12 – Frequency Response A. SUMMARY OF COMMENTS 1. The standard drafting team (SDT) for Project 2007-12 has not explained how compliance with draft standard BAL-003-1 is achievable; therefore, a key goal of Order 693 has not been met. a. BAL-003-1's objectives (from the project's web page) states "There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline." If one does not know why Frequency Response is declining, how can a BA ensure itself that it has sufficient Frequency Response in its area to meet its obligation? b. BAL-003-1 assigns Balancing Authorities (BAs) the requirement to meet a Frequency Response Obligation for their respective areas. However, BAs have no the authority to set requirements for suppliers of Frequency Response service: Generator Owners (GOs) as well as demand response resources. 2. Two existing standards (BAL-001-0.1a and BAL-002-0) also address Frequency Response. However, the pro forma Open Access Transmission Tariff (OATT) contained ancillary services associated with these standards prior to the standards being approved. a. The SDT needs to explain the relationship between BAL-001-0.1a, BAL-002-0, and draft standard BAL-003-1 since they all address an aspect of Frequency Response. b. BAL-003-1's objectives (from the project's web page) do not include a statement that having sufficient Frequency Response is necessary to arrest the frequency decline within the first seconds of a disturbance so that underfrequency load shedding (UFLS) is minimized. 3. There is no OATT ancillary service for the service in draft standard BAL-003-1. Unless commercial terms are established which define the relationship between BAs and Frequency Response providers, BAL-003-1 will not be implementable. Because commercial terms need to be defined in the OATT, we encourage NERC to work with FERC's Office of Energy Market Regulation and/or its Office of Energy Policy and Innovation to initiate proceeding with the goal of developing a new ancillary service – Primary Frequency Response Service. 4. A plot of frequency versus time after the sudden loss of generation is only contained in presentations for the technical conferences, but a plot is not in any of BAL-003-1's documents. Such a plot is needed in the standard (or in an attachment to it) so that the familiar reference points – A, B, and C – can be used in the standard's documents. 5. With regard to setting the Frequency Response Obligation by Interconnections in BAL-003-1: a. How can two Interconnections (Eastern and Quebec), which are not Registered Entities, comply with the requirement in Attachment A to set a Frequency Response Obligation? b. The SDT should explain its rationale for choosing "the largest category C (N-2) event identified" as the basis for setting an Interconnection's Frequency Response Obligation. 6. Project 2010-14-1 is related to Project 2007-10, and the two project teams should coordinate on these items: a. Both SDTs should put themselves in the position of a BA that must comply with R3 and all its subparts in draft standard BAL-012-1 and develop a hypothetical implementation plan for a BA to meet its Frequency Response Obligation. b. Both SDTs should work together to explain the relationship between Regulating Reserve, Contingency Reserve, and Frequency Response Reserve contained in BAL-012-1. B. REGULATORY BACKGROUND When FERC approved BAL-003-0 – Frequency Response and Bias – in Order 693, it issued NERC a directive in P. 375: …the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: … (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved." The standard drafting team for Project 2007-12 is currently addressing all but one of the items in the Order 693 directive. See below: Order 693, P. 375 (3) Directive Addressed by SDT? 1. Define the necessary amount of Frequency Response for each BA Yes 2. Define methods of obtaining Frequency Response No 3. Define methods of measuring that Frequency Response is achieved Yes This second item is critical. "Methods" can describe technical options, but it can also describe process options. While the project's "Frequency Response Background Document" dated October 2011 has a section on "methods of obtaining Frequency

Response" on p. 11, that section has six bullet points on the topic. The points are not integrated into a coherent approach that explains how compliance is achievable. Draft standard BAL-003-1 assigns BAs the requirement to meet a Frequency Response Obligation for their respective areas. However, BAs have no the authority to set requirements for suppliers of Frequency Response service: GOs as well as demand response resources. In addition, there are no OATT provisions that will compensate suppliers for the service BAs will ask them to provide. C. TECHNICAL COMMENTS 1. BAL-001-0.1a and BAL-002-0 NERC's Glossary defines of Frequency Response and Frequency Bias as follows: Frequency Response: (Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz). Frequency Bias: A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority [Area Control Area] ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection. Two existing standards are related to draft standard BAL-003-1. a. BAL-001-0.1a – Real Power Control Performance – addresses maintenance of frequency, within limits, by a BA in a steady-state (no disturbance) environment by measuring ACE. This requires BAs to have sufficient Regulating Reserve. The ACE equation includes a component for Frequency Bias. This component adjusts ACE when frequency deviates from 60 Hz, allowing a BA to contribute its Frequency Response to the Interconnection. In the OATT, this service is Schedule 3 – Regulation and Frequency Response. b. BAL-002-1– Disturbance Control Performance – requires BAs to provide sufficient Contingency Reserve so that ACE can be returned to its pre-disturbance level within 15 minutes. In the OATT, this service is incorporated into two schedules: Schedule 5 – Operating Reserve – Spinning Reserve Service and Schedule 6 – Operating Reserve – Supplemental Reserve Service. In both standards, the needed ancillary services were in the OATT PRIOR to the standards being approved. The reliability standards set performance requirements while the OATT sets the commercial structure for compensating providers. To meet the requirements of BAL-001-0.1a and BAL-002-1, BAs need Frequency Response (equipment) so that they have the "ability… to react or respond to a change in system frequency." Maintaining ACE is a Frequency Response service, but it is different from the type of service in draft standard BAL-003-1 and as described in the technical conference. The SDT should explain the relationship of all three standards since they all address an aspect of Frequency Response. 2. Draft BAL-003-1 Objectives The objectives of Project 2007-12 are excerpted below from its web page: Frequency Response, a measure of an Interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load, is a critical component to the reliable operation of the bulk power system, particularly during disturbances and restoration. Failure to maintain frequency can disrupt the operation of equipment and initiate disconnection of power plant equipment to prevent them from being damaged, which could lead to wide-spread blackouts. THERE IS EVIDENCE OF CONTINUING DECLINE IN FREQUENCY RESPONSE IN THE THREE INTERCONNECTIONS OVER THE PAST 10 YEARS, BUT NO CONFIRMED REASON FOR THE APPARENT DECLINE (emphasis added). The proposed standard would set a minimum Frequency Response obligation for each Balancing Authority, provide a uniform calculation of Frequency Response and Frequency Bias Settings that transition to values closer to natural Frequency Response, and encourage coordinated AGC operation. This statement has two shortcomings. First, the emphasized sentence above is discouraging because if one does not know why Frequency Response is declining, how can a BA ensure itself that it has sufficient Frequency Response in its area to meet its obligation? The standard should describe how a BA might comply with its Frequency Response Obligation in an appendix. (See the comments in Section D below.) Second, it makes no mention that having sufficient Frequency Response is necessary TO ARREST FREQUENCY DECLINE WITHING THE FIRST SECONDS OF A DISTURBANCE SO THAT UNDERFREQUENCY LOAD SHEDDING (UFLS) IS MINIMIZED. 3. Graphics A plot of frequency versus time after the sudden loss of generation is only contained in the presentations for the technical conferences, not in any of BAL-003-1's documents. Such a plot is needed in the standard (or in an attachment to it) so that the familiar reference points – A, B, and C – can be used in the standard's documents. 4. Physical response to loss of generation The workshop did a good job in explaining what occurs physically within an Interconnection after generation is lost. Those are summarized below for the SDT to review for any misunderstanding. a. At point A (pre-disturbance), an unspecified amount of generation is lost. b. Between point A and point C (the frequency nadir), several changes occur: i. Due to the loss of generation, load is greater than generation, and in response to this imbalance, generators "slow down" and frequency drops. Each generator's loss of speed releases power to serve the load, albeit at a reduced frequency. Generators with greater mass are preferred since they have more stored rotating power to release. Frequency

Bias setting in each BA's ACE equation allows this power to flow into the Interconnection. ii. Load is also reduced when frequency is reduced because loads such as motors slow down also and consume less power. Load reduction aids in arresting frequency decline. However, unless the frequency decline triggers the first UFLS step, no connected is lost. iii. Generator governors begin to respond. A generator's governor that can increase output when frequency declines provided certain characteristics are met. 1) The generator must be operating below its maximum capacity that can be achieved under automatic (i.e. non-operator intervention) operation. A generator with a 100 MW capacity and operating at 80 MW has "head room" to respond while the same generator operating at 100 MW cannot. 2) The governor's "dead band," which defines a range (+/-) of frequency changes that do not activate the governor, must not be so wide so as to effectively disable the governor from responding to frequency changes during a disturbance. 3) The governor cannot be overridden by "outer loop controls" on the generator. These controls countermand the governor's response, keeping the generator's output level unchanged. Governor response is the last to occur – it begins within seconds after the disturbance and continues until the generators with active governors reach their maximum capacity or until frequency is restored. In addition, properly devised demand response resources can substitute for governor-responsive generators. c. At point B, frequency is stabilized. All of items above occur automatically, without operator intervention. Collectively, these actions are referred to the "primary response" of the Interconnection to loss of generation. Subsequent responses involve operator actions that eventually return system frequency and ACE to a pre-disturbance ACE target. These subsequent responses are not the objective of draft BAL-003-1, but they are the objective of BAL-002-1. 5. Frequency Response Obligation Determination Regarding the Frequency Response Obligation for an Interconnection, Attachment A in draft BAL-003-1 states "Each Interconnection will establish target contingency protection criteria," with the default target "based on the largest category C (N-2) event identified." We have several questions: a. How can two Interconnections (Eastern and Quebec), which are not Registered Entities, comply with the requirement in Attachment A to set a Frequency Response Obligation? In fact, no Interconnection is listed in the Applicability section of BAL-003-1. b. We assume that "category C" in the Attachment A language above references Table 1 in the current TPL standards, but that should be clarified by the SDT. Does the SDT intend to restrict the category C events to those that only result in the loss of two Elements? This question is asked because category C in Table 1 is described as "Event(s) resulting in the loss of two or more (multiple) elements." c. The default target contingency in Attachment A is greater than minimum Contingency Reserve requirement in BAL-002-1 (R3.1), which is based on "the most severe single contingency." Why was the minimum requirement in BAL-002-1 not used? The SDT should explain its rationale for choosing "the largest category C (N-2) event identified" as the basis for setting an Interconnection's Frequency Response Obligation. 6. Frequency Response Obligation Measurement We summarized Frequency Response Obligation measurement below for the SDT to review for any misunderstanding. a. Frequency Response will be measured at point B due to technical limitations in measuring each BA's point C. However, point C can be measured for an Interconnection. Because the C to B ratio is highly consistent within an Interconnection, measuring the response at B also measures the decline at C is achieved. b. For compliance purposes, each BA's performance in meeting its Frequency Response Obligation will be based upon its median Frequency Response of at least 25 events, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz). D. FREQUENCY RESPONSE OPTIONS The discussion below is not inclusive, and the SDT is encouraged to provide guidance on compliance as recommended in Section C.2 above. 1. Value high inertia generators. Generators that are on line and spinning, even if loaded to their maximum capacity, provide MW by slowing down, and generators with greater mass are preferred. In engineering parlance, this is termed the inertia constant, H, which, for a given generator is: H = (Stored kinetic energy in megajoules at synchronous speed)/(Generator rating in MVA) Generators with a greater H constant have more value in arresting frequency decline than similarly rated generators with a lower H constant. 2. Value interruptible load on underfrequency relays. Many utilities have interruptible loads, and some of these could be configured to be shed load based upon frequency steps that are above the first UFLS step. As an example, direct load control programs for cycling residential air conditioners and water heaters could be configured to interrupt all appliances on the program for several minutes after a disturbance, with the appliances gradually restored after the frequency decline is arrested. 3. For generators that provide primary Frequency Response through governor action, value rapid response. The rate of increase in generator output due to governor response is both governor and prime-mover specific. The governor's droop determines how much it will increase signal generator power to increase when frequency declines. Also, generators with rapid power increase capability,

such as simple cycle gas turbines, can deliver the governor's signal to increase power more quickly. The more rapid a generator's response capability, the more it should be valued. a. Generators providing primary Frequency Response through governor action or automatically curtailed interruptible load also provide "Operating Reserve – Spinning," which is a component of Operating Reserve. It is defined in the NERC Glossary as follows: Operating Reserve – Spinning The portion of Operating Reserve consisting of: i. Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or ii. Load fully removable from the system within the Disturbance Recovery Period following the contingency event. The term "Disturbance Recovery Period" is used in BAL-002-1, and its default value is 15 minutes. To minimize UFLS activation, which can occur within seconds after a disturbance, primary Frequency Response is the key requirement, and the 15 minute time frame in Operating Reserve – Spinning is not relevant. However, a GO that provides primary Frequency Response via an active governor or a demand response provider that provides automatically curtailed interruptible load is also providing Operating Reserves – Spinning. E. OATT PROVISIONS Unless commercial terms are established which define the relationship between BAs and Frequency Response providers (GOs and demand response resources), BAL-003-1 will not be implementable. Because commercial terms need to be defined in the OATT, we encourage NERC to work with FERC's Office of Energy Market Regulation and/or its Office of Energy Policy and Innovation to initiate proceeding with the goal of developing a new ancillary service – Primary Frequency Response Service. This service would address automatic Frequency Response within a short time frame (up to about 30 seconds) after a disturbance. Overlap between Spinning Reserve Service and Primary Frequency Response Service would need to be addressed. F. COORDINATION WITH PROJECT 2010-14.1 After preparing the majority of our comments, a first-time request for comments on a related project, Project 2010-14.1 – Phase 1 of Balancing Authority Reliability-based Controls Reserves – was posted on June 4. This project includes a new draft standard BAL-012-1 that has a proposed definition for Frequency Response Reserve – "An amount of reserve automatically responsive to locally sensed frequency deviation during the primary control time frame." That definition is similar to the ancillary service proposed above. Both SDTs should put themselves in the position of a BA that must comply with R3 and all its subparts in draft standard BAL-012-1 and develop a hypothetical implementation plan for a BA to meet its Frequency Response Obligation. If they did, they would understand why BAs have little understanding of what they must do to comply with draft BAL-003-1. Both SDTs work together to explain the relationship between Regulating Reserve, Contingency Reserve, and Frequency Response Reserve contained in BAL-012-1.
Group
Bonneville Power Administration
Chris Higgins
Transmission Reliability Program
Chris Higgins Bonneville Power Administration Transmission Reliability Program cmiggins@bpa.gov 360-418-2132 Submitting on behalf of the BPA's AGC team. BPA continues to fundamentally disagree with the approach that BAL-003-1 is developing into. Please reference BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found here: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf. BPA also believes that having a special interest group present their perspective on the standard and a consultant provide a sales pitch in relation to load response was inappropriate and ill-served.
Individual
Don McInnis
Florida Power & Light
The conference was very informative. Of particular interest was who should be responsible for providing frequency response. The assignment to the BA was well supported and logically presented. The details presented in the conference were different than those in the original version of the standard i.e. the frequency selected to protect for was modified from 59.7 to " prevailing". The prevailing frequency if prevailing is interpreted as dominant is 59.3Hz yet the standards team choose 59.5Hz without explanation or justification. There was also a lack of technical justification in increasing the frequency bias minimum from the original 0.8% to 0.9%. While a minimum should be established there should be no link to frequency response as the two are no longer related.
Individual

Bob Frost
Portland General Electric
1. BAL-003-1, Attachment A, states that the ERO will provide quarterly posting of candidate frequency events. It then states it will post the final list of frequency excursion events used for standard compliance by December 15 each year. Because the quarterly postings are only candidates and the median frequency response is the measure, Balancing Authorities cannot always be certain they will be compliant with the Standard until December 15. 2. FRS Form 1, sheet "Data Entry", requests entry by the Balancing Authority of next year's FRO (cell O31). However, per Attachment A, this information is provided by the ERO only after Form 1 is submitted by the Balancing Authority. A Balancing Authority is only able to estimate their FRO. 3. FRS Form 2, sheet "Entry Data", has the Balancing Authority modify formulas for cells C8 and C11 in order to identify the beginning and recovery from the event. This is tedious as Form 2 must be completed a minimum of 25 times each year. The spreadsheet should be authored so that the user does not need to modify formulas. The sheet "Data" on Form 2 could have cells adjacent to the data that are marked to identify these points.
Group
MISO Standards Collaborators
Marie Knox
MISO
We have a strong concern related to the handling of variable bias. The drafting team is fully removing the floor for the minimum amount of bias for these BAs and only asks bias to be equal to natural frequency response when frequency is off normal. There should always be some bias (perhaps 40% of FRO) provided to the Interconnection and there should be some minimum annual average. This can be managed through the year and still will be well less than the current obligation under BAL-003-0. Since there is no firm technical guidance on how variable bias is to be set, to leave this gap will cause a mass movement of BAs to report as variable bias entities. It will also leave the door open to gaming to artificially improve CPS, DCS and BAAL performance. For example, an algorithm that takes bias to a small positive number once each 15 minutes would assure the BA will never fail DCS or BAAL.
Group
LG&E and KU Services
Brent Ingebrigtson
LG&E and KU Services
LG&E and KU Services have two comments/questions related to the material presented at the FR Technical Conference: 1. Data was presented that illustrates a decline in the Frequency Response of the Eastern Interconnect for the period 1994 through 2010. Since FR is partially related to the amount of on-line generation available at the time of the contingency, has the SDT investigated the amount of spinning reserves typically available on the Eastern Interconnect during the same 1994 to 2010 period? If so, was there a correlation between the decline of Frequency Response and available spinning reserve? 2. During the conference, mention was made that there is a cost for obtaining Frequency Response – mainly the cost of unused spinning generator capacity. However, no data, analysis or estimates were presented as to what these costs might be. Cost estimates for attaining the desired amount of Frequency Response would be useful to the industry and FERC in evaluating the proposed Frequency Response standard.
Individual
Michael Goggin
American Wind Energy Association
AWEA appreciates the opportunity to comment on NERC's ongoing work on frequency response standards. Based on the presentations at NERC's May 2012 technical conferences on frequency response issues, it appears that consensus exists around three important points, which we would like to highlight in our comments. We are pleased that these points appear to be embodied in the ongoing work of the standards drafting team on frequency response (BAL-003-1). 1. The balancing authority (BA) should be the entity responsible for meeting a frequency response standard. This responsibility would fit in well with a BA's existing responsibilities for maintaining system frequency within acceptable bounds, such as CPS 1&2 and DCS requirements. Just as a BA currently obtains the reserves and other services required to meet these frequency standards and operates according to these standards, the BA is the logical entity for taking on those responsibilities for frequency

response. The BA is the only entity that has a real-time awareness of overall power system needs and capabilities, and is thus ideally suited for meeting a frequency response standard. 2. A BA's selection of resources to provide frequency response service should be market-based. As was explained at the technical conferences, different resources have widely divergent costs for providing frequency response. Many resources are likely to be able to provide significant frequency response at very low cost, while other resources are likely to face significantly higher costs for providing this service. For example, maintaining the capability to provide sustained frequency response from a wind plant would require holding the wind plant below its operating capability at all times, foregoing significant production of near-zero-marginal cost, zero emissions wind energy. As a result, under normal operating conditions, the wind plant's opportunity cost for providing frequency response capability is likely to be significantly higher than the cost for many other generating resources, which would be able to save on fuel costs by operating below their maximum output. Innovative technologies, including some forms of demand response and energy storage, are also likely to be able to provide frequency response at relatively low cost. The BA is well-positioned to use a market-based mechanism to select the least-cost frequency response resources from the available resources, as conditions change in real-time. This market-based incentive should also provide sufficient incentive for most potential resources to install any equipment necessary to provide frequency response. The market mechanism should be designed to pay for performance, so that frequency response resources are incentivized to provide services with the maximum value for the power system. 3. The decline in frequency response on the Eastern U.S. power system pre-dates the introduction of wind energy and appears to have been caused by changes in how conventional power plants are operated, and not in any way tied to the increased use of wind energy. As NERC noted in comments submitted to FERC on October 14, 2010: "Frequency response of the interconnected North American electric systems has shown a significant decline for several years. The reasons for the decline are numerous, including: • A trend toward larger governor deadband settings, exceeding the historical typical setting of ±36 millihertz (mHz); • Use of steam turbine sliding pressure controls; • Loading units to 100 percent of capacity leaving no "headroom" for response to losses of generation; • Blocked governor response; • Once-through boilers; • Gas Turbine inverse response; • Withdrawal of primary frequency response of generators by MW setpoints, resulting in limited time of response; and • Changes in the frequency response characteristics of the load. These changes have been evolving for some time and are not the direct result of the emergence of renewable resources such as wind and solar." Data presented at the technical conference indicated that only around 30% of generators are currently providing frequency response. Much of the decline in frequency response provision appears to result from generator owners maximizing efficiency and minimizing costs under current market structures. Implementing a market-based mechanism to select the least-cost frequency response resources from the available resource pool would allow conventional generators to be appropriately compensated for any costs they incur for providing frequency response while simultaneously selecting the least-cost resources for the power system. The technical conference also discussed the fact that only 1/3 of the 30% of generators that are providing frequency response (so 10% of the total generation fleet) sustain that frequency response for more than a short period of time. Part of the problem appears to be that some current energy imbalance tariff provisions may penalize generators that increase their output beyond the scheduled amount, and therefore generators are limiting the duration of frequency response following a system disturbance to avoid imbalance penalties. At the technical conference, there appeared to be widespread support for reforming those energy imbalance tariff provisions to remove that perverse incentive, which is commendable.
Group
ISO/RTO Standards Review Committee
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Introduction The undersigned members of the ISO/RTO Standards Review Committee (SRC) appreciate that NERC provided the opportunity to comment upon NERC's Frequency Response Technical Conference. The Conference addressed an important topic in which the SRC is deeply interested – primary control. The SRC notes that the Conference's presentation of the various and diverse perspectives of this topic highlighted the continued need to resolve and address several issues: • The need for a common language for discussion • The need for an objective analysis of a reliability need • Given the proof of such an objective reliability need, there is a need to define the quantitative parameters involved in measuring the objective • The need to justify the creation of a

mandatory standard that is relevant to the current and future BES. That includes: o Reviewing relevancy of old standards o Clarifying discussions o Objectively assigning responsibilities Discussion Terminology/Common Language The SRC noted that the presenters did not share a common set of terms. The term Frequency Response was used to address issues that are separated by time frames and that deserve separate discussions. Frequency Response was used generically to mean any activity related to controlling frequency. Frequency Response was also used to mean undirected control (such as the change in generator output caused by a governor). Frequency Response was used to mean directed control (aka secondary control). It was also used to mean the Area Control Error equation. Rather than relying on the broad and ill-defined term Frequency Response, the SRC suggests that either newly minted terms be created or that more traditional terms such as Primary Control Response and Secondary Control Response be used. All too often the presenters crossed the traditional boundaries thereby decreasing the clarity (and the value) of the discussion. There was also a tendency to use the term “Service” for both the traditional Ancillary Services (Load Following (aka Economic Dispatch); Spinning reserves; Supplemental reserves; Regulation service (aka AGC); Reactive and voltage control service; Black start) and for conditions that exist (i.e. the reaction from generators to changes in frequency). There is a tendency to equate Frequency Control through tie-line bias (typically this is AGC or secondary control) with Primary control (Dave Lemmons); Bias vs. Beta (is also a secondary control issue but it is linked because the parameters themselves are related to the primary response experienced; but they drive secondary control problems and solutions). In short the Bias is a 1st order approximation of what the magnitude of primary response that goes into the ACE equation to drive secondary control. Unless care is taken with the terms, it is easy to envision differences in discussions. Good resolutions of problems caused on the secondary control system were presented (Terry Bilke) but that need is relatively independent of this SDT. For our comments the SRC will focus on Primary Control response and use the terms primary, primary response, or primary frequency response rather than Frequency Response. Need The SRC notes that the presenters offered a variety of reasons for a “Frequency Response” standard: • Because the governor response in the Eastern Interconnection changed (or appears to be changing) • To avoid Under-Frequency Load Shedding relay operation • To avoid problems for Secondary control (valid need but not a valid justification for Primary Frequency control standard) (Howard Illian) • FERC Order 693 o Determine the appropriate periodicity of frequency response surveys o Define necessary amount of Frequency Response for reliable operations with methods of obtaining response and measuring that the frequency response is achieved • FERC Technical Conference The SRC observes that the presenters are attempting to address the goal of operating at a reasonable margin away from both UFLS (under-frequency) and OFR (over-frequency) settings, and to avoid any single event (contingency) causing those relays to activate. The SRC fully supports that objective. Several presenters mentioned the above objective and addressed the amount of post-event governor response, i.e. response that was activated after the frequency was arrested. Presenters recognized that not all suppliers are generators, and not all generators have governors, and not all of those generators respond in the same way. They also note that BAs do not all own generators. One presenter documented that the Eastern Interconnection has the worst post event response but also has the highest frequency arrest level (i.e. are farthest from a relay trip point) Most presenters expressed preference to impose Frequency response production requirements on BAs. Most presenters want to focus on the Eastern Interconnection. The SRC believes the requirement addressing primary frequency response must: • Relate to the frequency nadir point not the post event response • Apply to and be assigned to “ALL” Functional Entities registered for that applicable group • Reflect the capabilities of the functional entity to provide the mandated service. • Address both supply capabilities as well as appropriateness of relay settings If the objective is to avoid tripping relays and to minimize the risk of tripping those relays then the requirement must focus on that objective. Some presenters stated that it is traditional and simply easier to focus a Frequency Response requirement on BAs. Others stated that there were too many suppliers to impose a frequency response mandate on the suppliers. The SRC as well as NERC have stated the intention to have performance based standards and to move away from procedural requirements. The majority of the Technical Conference presenters focused on procedural solutions (i.e. governor response) and tried to indicate that both generation and demand response could serve as response providers. Bob Cummings of NERC showed that the typical worst response of the EI was equal to or higher than the best responses in ERCOT or WECC. In effect the concern about lack of post event response does not reflect the margin of reliability experienced even with the “hockey stick” response. Given the fact that none of the presenters proposed increasing the ERCOT and WECC responses to be as effective as the EI response, the observed decrease in the Eastern

interconnection could be seen as a type of “right-sizing” of response – i.e. the east is now coming closer to the rest of North America. Supply The SRC does recognize the change in frequency response in the EI, but is concerned that mandating ill-advised requirements on the wrong applicable entities will foster the loss of the provision of primary response service and not help it. If the “supply” requirement is placed on a coordinator, then the energy producing assets have no incentive to provide a service that takes away from other more lucrative products. If the requirement is placed on a subset of suppliers then those suppliers will likely mimic the suppliers in the other subset and not offer any service at all. The idea of focusing on one given solution – governor response – creates disincentives for new technologies. The Industry is now adopting those innovations without a mandate and should be allowed to continue that expansion without the threat of a standard that would impede such expansion. Suggestions The SRC believes there is a need for more open presentations including people not as focused on governors. The majority of presenters were experts in a given area. Their expertise seemed to preclude exploration of other options than the current option/approach. It should be noted that a Governor-centric requirement violates Order 693’s mandate to be resource neutral. It is time to have a discussion of the role of coordinators (like RCs, TOPs and BAs) who can and do use a palette of tools and services to address a given system condition without being obligated to answer for non-production. An alternative could be that such entities are required to provide assessment and analysis but not production; or they are required to arrange for, purchase, or otherwise provide capacity (not energy) capable of providing the primary frequency response. Many of the presenters seemed to be in a vertically integrated industry where the coordinator is the owner and operator. That is no longer universally true. A primary frequency response service for an interconnection may be calculated as discussed by the presenters, but the mandate must be developed so that the default entity will be obligated to provide or purchase the obligation (thus opening the opportunity to all new innovations). Should that be the LSEs who use the service; the suppliers who provide the service; the coordinators who integrate all of the services; or to allow a combination without specifying “how” it must be done? Other SRC Considerations raised by presenters’ comments It is invalid to avoid imposing a requirement on the appropriate applicable entity simply because there are many of them; if other standards apply to the same applicable entities then this one can also. Speed should not be a driver contrary to what one presenter stated. As presenters said we are fine today without any mandatory standard for primary control. This prompts the question “why the need for speed?” Because we can correct problems with the requirements later, via SARs, is NOT a justification for creating an inaccurate standard. Why should TOPs be permitted to set relays anywhere, but GOPs be obligated to set governors to avoid those relays? Focusing on improving details of what we have today does not make today’s paradigm better!!!! A standard should not serve as a field test for an idea!!!!
Individual
Laura Lee
Duke Energy
Duke Energy appreciates having the opportunity to participate in the Frequency Response Technical Conference. It was a very helpful for our team to hear the issues that were brought by others to the discussion, along with the opinions of NERC staff, the Frequency Response Standard Drafting Team (FRRSDT), and FERC staff. Duke Energy provides the following comments and proposed resolutions to some of the issues we believe should be addressed. Frequency Response Obligation (FRO) As the FRRSDT reviews all of the issues discussed and subsequent comments provided, we ask that consideration be given to drilling down to the “root cause” of the issues, to see what is driving them. We have found one of the root causes of a few issues to be the allocation of the FRO. In the current proposal, a BA’s FRO is the Interconnection Frequency Response Obligation applied to the ratio of the BA’s generation and load at peak divided by the Interconnection BA totals of generation and load at peak. Including generation in the allocation helps accommodate treatment of generation-only BAs (representing perhaps one percent of the total generation in the Interconnection), but in the process creates issues for both individual generating resources and all other BAs. Duke Energy believes that the FRO allocation should be based upon load only, based upon the numerous issues and inequities that an FRO allocation based upon load and generation would otherwise create, including but not limited to: a) An FRO allocation based upon generation at peak treats resources on a non-comparable basis within a “traditional” (load and generation) BA, biased against resources dedicated to peaking operation (CTs as an example), and in favor of resources which may not operate at peak capacity during such times (wind resources as an example). b) A third party resource added to a BA footprint

would add to the BA's response requirement, but the third party resource would have no requirement to provide frequency response. If such resources are only providing peaking energy to off-system loads, the generation would add to the response requirement for the BA for the year, though the resources may run a small fraction of that time. Even if the resources were capable of providing frequency response when online, they may do little to compensate the BA for the increased year-round requirement. The allocation methodology creates the issue that the BA must now address – compensation for the increased response requirement or some other tariff provision to make it whole. c) The allocation methodology creates a gaming opportunity – a strategy to purchase external energy across the peak would be a small premium to pay to achieve a reduced Frequency Response Obligation for the year – but a large price to pay for the BA with the resources selling off-system outside its control. d) Discussed further below, the inclusion of generation in the FRO allocation creates a significant discrepancy between the methodology used to determine the FRO and the methodology used to determine the minimum Frequency Bias Setting. In our opinion, these are among the issues that neither the BAs nor the resources need to face. An allocation based upon the load within the BA rather than load plus generation would resolve them. An additional modification to enhance equitable treatment and eliminate gaming is the use of total energy for the period rather than peak loads in the FRO allocation. There is uncertainty that the use of 12 monthly peaks accurately represents the load benefiting from the continuous provision of Frequency Response. Similar to the gaming discussed above for generation, BAs capable of "peak shaving" are able to reduce a year-round requirement based upon a few hours of operation. Duke Energy proposes that the determination of a BA's FRO be the Interconnection FRO applied to the ratio of the BA's NEL (for those submitting EIA-714 reports, this would be the annual total in column e of Part II, Schedule 3; for others, this would be the sum of LSE NELs in the BA as reported for determination of NERC and Regional fees) divided by the Interconnection BA totals of these NELs. Basing the FRO allocation upon annual energies rather than peak loads eliminates the potential for a year-round FRO to be pushed to others by peak shaving if a peak value is used. The FRO for generation-only BAs (representing approximately 1% of the total generation within an Interconnection) can be set to a fixed percentage of total capacity, similar to current requirements for calculating the Frequency Bias Setting. Frequency Bias Setting (FBS) Notwithstanding our concern raised in the past that the secondary control measures are too tightly bound to the FBS and believing that in some cases the FBS is used as a convenient measure of BA size, Duke Energy agrees with the proposal to gradually reduce the magnitude of the FBS to some margin above the natural Frequency Response of the Interconnection. However, as proposed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" dated February 21, 2012, the allocation of the FBS reduction would be a margin based upon peak load or peak generation, rather than a margin based upon a methodology similar to that used for the allocation of the Frequency Response Obligation. As an example, based upon the proposed FRO allocation using load plus generation at peak, two BAs with the same peak load, but with differing levels of generation at peak due to off-system transactions, would have a different FRO allocation; however, these two BAs would be given the same minimum Frequency Bias Setting based upon a percentage of peak load only. A generation-only BA with the same amount of generation as a traditional BA serving a similar amount of load, would have an FRO allocation approximately half that of the traditional BA, however these two BAs would be given the same minimum FBS. Under the proposed procedure for reducing the magnitude of the FBS, the generation-only BA would always have a minimum FBS set almost twice what it would need to have compared to the traditional BA. We believe that the incremental reduction in the FBS will not achieve an equitable allocation in its final state. Duke Energy believes that the minimum FBS for each BA should be reduced in magnitude to a fixed percentage above each BA's FRO (but no lower individually than its FRM), while assuring that the Interconnection FBS remains at some margin above the Interconnection FRM. The current procedure posted for the FBS reduction will not achieve that equitable allocation, as the minimum FBS will always be based upon a different methodology than the FRO allocation in its current form. Upon request, Duke Energy can provide a procedure which could be used for determining the minimum FBS which would allow the minimum FBS for each BA to be incrementally reduced in magnitude over time based upon the FRO allocation, and ensure that the Interconnection FBS remains at some margin above the Interconnection FRM. However, given the timeline for moving this standard forward, Duke Energy would propose that consideration be given to basing the FRO allocation on load only as discussed above, setting a value for the generation-only BAs, and returning to the issue of aligning the methodologies used for the FRO allocation and minimum FBS calculation at a later time. Variable Frequency Bias Setting Duke Energy disagrees with the FRRSDT's proposal not to require a minimum

FBS for BAs using a Variable FBS in multiple BA Interconnections. There are no defined requirements on how a Variable FBS SHALL be calculated, yet its use changes not only the ACE measured against the BAL-001 secondary control requirements, but also the bounds of those secondary control requirements. Overall, Duke Energy questions whether the proposed standard should continue to allow the use of a Variable FBS in calculating ACE or secondary control performance. Duke Energy does not question the value of a BA implementing the logic of a variable FBS in its generation control algorithm, along with other factors to more efficiently control resources, however its operation should be measured in a manner consistent with all other BAs. Nathan Cohn was of the opinion that the secondary control assistance provided by the FBS should be a shared obligation. In the publication "IEEE Transactions on Power Systems, Vol. 3, No. 3, August 1988", Cohn noted the following in the article VARIABLE, NON-LINEAR TIE-LINE FREQUENCY BIAS FOR INTERCONNECTED SYSTEMS CONTROL: "The very conditions that create a variable frequency response to which an area bias is linked as in the subject paper would create a variable level of bias assistance by the area in fulfilling system needs." Nathan Cohn goes on to state, "It is of course recognized that the extent of bias assistance to be scheduled by individual areas is, as are all operating practices, a matter for system operating personnel to determine. This discusser suggests, however, that there are potential advantages in bias assistance based on a common percentage-of-peak for all areas. It would provide an equitable, cooperative, and democratic systems approach." As supported by the statements of Cohn, Duke Energy believes that the assistance provided by the FBS should be a shared obligation equally applied to all BAs by using a fixed FBS in the calculation of ACE and secondary control performance. BAL-003-1 Documents The document, "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" dated February 21, 2012, no longer has a reference to being "Attachment B" to the draft BAL-003-1 standard. Duke Energy would appreciate clarification of whether this document is within the scope of what will be eventually be included in the ballot of Project 2007-12 — Frequency Response, and what process would be required to make any subsequent revisions to the procedure.
Individual
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MISO
The Midwest Independent Transmission System Operator, Inc. ("MISO") appreciates the opportunity to comment on the technical conferences that NERC recently held on Frequency Response issues, and, in particular, the proposed changes to BAL-003. MISO adds only two brief comments here. MISO agrees with the proposed change in BAL-003-1 with respect to the calculation of minimum amount of frequency response to be provided by a Balancing Authority (this is the Frequency Response Obligation under Requirement R1 of BAL-003-1). The allocation of Frequency Response Obligation among Balancing Authorities in an Interconnection is to be based on peak load data, which is a reasonable approach to determining what proportion of frequency response should be contributed to each Balancing Authority. MISO also agrees with the manner of calculating each Balancing Authority's Frequency Response Obligation under Requirement R1; the proposal by the Standards Drafting Team will ensure that adequate frequency response is provided by each Balancing Authority. At the same time, the Standards Drafting Team should reconsider its approach to variable bias. Balancing Authorities with variable bias are not subject to some of the requirements. Variable bias methodologies are not identified, and that lack of an identified methodology opens the opportunity for individual Balancing Authorities to engage in gaming (such as having bias go to zero or a small positive number every 15 minutes to ensure DCS and BAAL is never failed).