Individual or group. (24 Responses)
Name (9 Responses)
Organization (9 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Contact Organization (15 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (4 Responses)
Comments (24 Responses)
Question 1 (20 Responses)

Group
MRO-NERC Standards Review Forum
Joe Depoorter
Madison Gas and Electric Company
We commend the drafting team on the improvements made since the last posting. Below are our concerns and recommendations for improvement. The NSRF is concerned that the lowering of the threshold to 900 MW for the Reportable Balancing Contingency Event in the Eastern Interconnection, coupled with the proposed change from quarterly average performance to individual event performance will increase customer costs and significantly increase compliance exposure for no difference in reliability risk. Because the interconnection is over-biased (ACE overstates resource loss) and operators operate conservatively, they will likely deploy contingency reserves for any loss over 800 MW. Our recommendation is that the standard uses the lesser of 80% of MSSC or 1000 MW for the Eastern Interconnection. Don't Change from Present Quarterly Reporting: We have fundamental concerns with changing the current quarterly reporting to exception reporting. We can find no directive for this change which increases compliance exposure and will have unintended consequences in how Reserve Sharing Groups (RSG) will operate. A failure of a contingency resource to start or start a minute late can cause performance that has a very low score for that single event, even though recovery is only a minute late or two late. There are RSGs that mitigate this compliance risk by deploying reserves for much smaller events, which helps reliability by quickly recovering from smaller events and replenishing these reserves as well as giving operators repeated practice in reserve deployment. Since each and every event is individually sanctionable, these RSGs will quickly change their rules to raise their reportable threshold to the interconnection minimum. Exception reporting will also eliminate a data source that is used for NERC's RAPA group and the State of Reliability Report: http://www.nerc.com/pa/RAPA/ri/Pages/DCSEvents.aspx, which is another step backward. We believe there should be a single quarterly report for R1 and R2. The R1 portion would be very similar to today, to include reporting of events > MSSC (but not part of compliance evaluation). The quarterly R2 portion of the report should have the number of hours the BA

had reserves < MSSC and an identifier which hours were excludable under 2.1 through 2.6. The VSLs should be based on the number of hours that reserves were < MSSC and not excluded: • Low: 2 or fewer hours (represents 0.09% of the hours in the quarter) • Medium: 3-5 hours • High: 6-9 hours • Severe: 10 or more hours (10 hours represents 0.5% of the hours in a month) NERC is trying to move away from zero defect standards. This standard should be structured to support that concept. The reporting approach need not hard coded in requirements, but could be compliance section of the standard. We also had comments on a few specific items in R1. Our suggested wording changes are in [ ]. *** 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated [or depleted]. *** Contingencies can happen that take away reserves without the reserves being activated. And if these contingencies aren't "sudden", then it appears there is no acknowledgment of the reserve loss under the standard. *** (ii) after multiple Balancing Contingency Events for which the combined [capacity] magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. *** Contingencies of partially loaded generators remove not only MW from the BA, but the reserves they had as headroom. It is possible to have multiple contingencies where the MW loss is < MSSC, but reserves that were lost completely deplete the BA of its contingency reserves. There should be clarification that the magnitude loss is based on capacity, not MW loss.
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
There is a possible inconsistency in the terms Balancing Contingency Event, and Reportable Balancing Contingency Event. Balancing Contingency Event is defined as "Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute..." Reportable Balancing Contingency Event is defined as "…(ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE…" By its definition, the Balancing Contingency Event, in the extreme, is an unlimited number of single events, as long as they are separated by less than one minute. Is it intended for a Reportable Balancing Contingency Event to only encompass what happens in the first minute as it is worded? In the NERC Glossary, Reportable Disturbance is defined as "Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance." The definition of Reportable Balancing Contingency Event should be revised to incorporate this definition, and should be made to read"…(i) Reportable Disturbance, or…". With this revision, when BAL-002-1 is retired the definition of Reportable Disturbance can be retired as well. Regarding the Rationale for

Requirement R1, should Reportable Area Control Error be Reporting ACE? Reporting ACE is in the NERC Glossary, Reportable Area Control Error is not. In the second paragraph of the Rationale for Requirement R1 that reads"…as described in R1.3 below…" should be revised to read "as described in Part 1.3…". Measure M1 should be revised to read "…that demonstrates compliance with Parts 1.2 and 1.3.". In Requirement R2, and Measure M2 "Firm" should not be capitalized. "Firm Load" is not in the NERC Glossary. It should be revised to read firm Load. Additional comments: 1) The proposed standard continues with several "compliance traps" which will hamper operators' effective use of Contingency Reserves to mitigate reliability problems, and then could cause compliance exposure due to auditor interpretation. For example, R1 would require a BA to deploy at least some of its reserves in order to declare an EEA exemption even if there may not be an immediate need to do so. 2) There are contradictory portions of the standard which would leave operators confused and again lead to compliance exposure. a. For example, Part 1.3 (ii) does not include an exemption for deploying Contingency Reserve for a Contingency that is not a NERC defined Balancing Contingency Event. R2 does have an exemption for this and other scenarios. The term "sudden" being included in the definition of a Balancing Contingency Event is the source of the problem. See the second scenario of Attachment A (sent by E-mail to Darrel Richardson). b. R1 does not treat subsequent Contingencies in a consistent manner, again related to the term "sudden" being included in the definition of a Balancing Contingency Event. See the first scenario in Attachment A (sent by E-mail to Darrel Richardson). 3) There are several problems with the definitions including definitions of Most Severe Single Contingency (MSSC), Contingency Event Recovery Period (CERP), and Balancing Contingency Event (BCE). a. MSSC does not include concurrently dropped load which may cause a Balancing Authority to carry extra Contingency Reserve beyond its actual MSSC. b. BCE is unclear with regard to both generation and transmission events. (Also consider if A. Item b within the BCE definition instead referred to an unplanned change in ACE as opposed to an unexpected change in ACE.) 4) Regarding R2: a. R2 is far more complex than necessary, is unclear, and contains potential for gaming. b. Much less complicated language is proposed here, based on the original NERC Policy 1. Suggest the revision of R2 to read: R2. The Responsible Entity, if deficient in Contingency Reserves, has 90 minutes to restore. If the Responsible Entity experiences a Reportable Balancing Contingency Event during this time an additional 15 minutes are allotted." An alternative suggested rewording of R2: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering all other events that may reduce this amount. This, together with the recovery provision in R1 (results-based requirement) and the provision in Requirement R6 and Attachment 1 of EOP-011-1 (which defines EEA levels) would collectively take care of many of the conditions listed in the proposed Requirement R2 including active monitoring of the amount of reserve to meet the Contingency Reserve requirement. R2 as presented in this draft requires a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 as shown preceding. We believe this together with the recovery provision in R1 would take care of many of the conditions listed in the proposed Requirement R2. c. The language in Part 2.2 regarding Operating Instruction appears to allow operating personnel to create exemptions from R2 at will. d. Requirement R2 continues to not include a number of “grace hours” per quarter, as requested in some industry comments. It may have a net effect of increasing the amount of available contingency reserve to some BAs which may marginally increase reliability. However, this needs to be balanced against increased operating costs due to carrying more reserve. e. Requirement R2 may produce a perverse incentive. A BA may let its ACE remain negative to keep the reserve monitor numbers above MSSC. Also, without a number of "grace hours" per quarter, there may be a susceptibility to loads running unexpectedly high near the end of a Clock Hour, causing a miniscule shortfall that results in an occasional "nuisance" compliance violation. f. R2 also causes BAs to carry much higher Contingency Reserves than necessary during the latter portions of the hour in order to “make the numbers come out right” if they are below MSSC in the beginning of the hour. g. Requirement R2 creates an artificial increase in reserves in order to maintain an amount over-and-above that required by the standard to meet non-DCS operational events, thereby increasing costs to ratepayers for no increase in reliability. h. R2 will encourage operators to not deploy reserves when needed for reliability in order to meet compliance with this requirement, which could be detrimental to reliability. i. Entities that have to shed firm customer load (because load cannot be shed fast enough) to maintain reserves to meet compliance with this requirement is not an action that should be taken for reliability. j. In our previous comments, we found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met requirement R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. k. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted item may be added under Part 1.3 in R1: • When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the excedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL). 5) The last sentence of metric M2 which splits a Clock Hour into sub-periods is difficult to follow and seems to add unnecessary complexity in determining compliance. 6) When the exemption in Part 2.6 becomes relevant, it most likely will occur within the middle of a Clock Hour. It is not clear if "instantaneous values showing reserves" refers to the sum of Contingency Reserve available plus Firm Load that can be shed. 7) Part 1.3 and R2 should be cognizant of unexpected loss of reserve without it being accompanied by a loss of power being delivered. In the last posting, we expressed a concern with the term “sudden loss” (see below). We are unable to find any response in the Summary Consideration report that addresses this comment. Please consider these comments and provide a response. A Balancing Contingency Event is vaguely defined as a “Sudden loss of generation...” or “sudden decline in ACE...”. The

word “sudden” is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where it says that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: “Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein.” The SDT’s response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. To summarize, the January 2015 version of BAL-002-2 could be improved by providing better clarity within the definitions and making simplifications that yield a more "operator-friendly" standard. There is a concern that the complexity and nuances of the proposed standard in some circumstances could be a distraction to the operator when more important reliability tasks need to be performed.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
PJM
Individual
Leonard Kula
Independent Electricity System Operator
1. In the last posting, we expressed a concern with the term “sudden loss” (see below). We are unable to find any response in the Summary Consideration report that addresses this comment. Please consider these comments and provide a response. A Balancing Contingency Event is vaguely defined as a “Sudden loss of generation...” or “sudden decline in ACE...”. The word sudden is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where it says that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: “Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein.” The SDT’s response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. 2. In our previous comments, we found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met the requirement in R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed

in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. R2 as presented in this draft requires a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 with the following: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering all other events that may reduce this amount. We believe this together with the recovery provision in R1 would take care of many of the conditions listed in the proposed Requirement R2. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted items may be added under Part 1.3 in R1: • When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL)
Group
Seattle City Light
Paul Haase
Seattle City Light
Seattle City Light supports Balancing Authorities having the flexibility to use Contingency Reserve to respond to other reliability events and votes affirmative for this ballot. Seattle would support the draft more, however, if the term "clock hour average" was replaced with "instantaneous value" throughout the Standard. Using Hourly averages places entities in the position where they may be incentivized to have less Contingency Reserve than their current Most Single Severe Contingency for large percentages of key operating hours. From a financial perspective, there is nothing in this revision stopping a Balancing Authority from having less Contingency Reserves than their Most Single Severe Contingency during the last 20 to 30 minutes of every steep load pick up hour every day.
Group
Florida Municipal Power Agency
Carol Chinn
Florida Municipal Power Agency
FMPA supports the comments of Duke Energy
Individual
Kathleen Goodman
ISO New England

Agree
NPCC RSC and IRC SRC
Group
Arizona Public Service Company
Kristie Cocco
Arizona Public Service Company
APS would like the Drafting Team to clarify the following question about the draft language. R1.2 states “A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.” Since only a Balancing Authority can be declared to be in an RC-approved EEA, how would that impact the RSG that the Balancing Authority is a member of since that would be how they would be reporting their compliance with R1? Differently stated, does the RSG that the BA is a member of receive a waiver from R1 if the member BA is in an RC-approved EEA?
Group
Con Edison, Inc.
Kelly Dash
Consolidated Edison Company of New York
Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material section: there is no substantial information contained in this section of the document. Is it the intent of the drafting team to fill-in these sections at a later date? If so, when would it be completed? If not, why not?
Individual
Terry Bilke
MISO
We commend the drafting team on the effort committed to this project and appreciate the improvements. We also appreciate the various objectives the team is trying to meet, but believe it is time to step back and ensure we are moving in a direction where NERC is trying to go with clearer, results-based standards. We understand that the team is trying to meet their interpretation of Order No. 693 directives. We respectfully submit that much of what the FERC directed may be moot as the directives related to primary, secondary, and tertiary control, have been met by other standards projects. This is particularly true considering the equally effective R2 (Balancing Authority ACE Limit, BAAL) in BAL-001-2 and a performance based Frequency Response Standard. The current BAL-002 is well understood by system operators and performance as posted on the NERC “Adequate Level of Reliability (ALR) Metrics” website has been stellar. The draft out for comment is not easily understood, adds complexity, and will likely increase customer cost for no discernable reliability value. If the

standard effort reaches an impasse, it may be time to hold a technical conference to get resolution on a few key items: 1] What should be the obligation of the Balancing Authority for events > MSSC? [We suggest that such events are reported to demonstrate best efforts were made, but compliance is not assessed. The BA is still accountable for BAAL. Finally there are backstop standards as load shedding is mandated in the EOP and IRO standards for harmful frequency conditions and IROL exceedances] 2] What constitutes a continent-wide contingency reserve policy? [We believe the policy could be met by developing simple definitions for the various categories of operating reserves as any can be used to meet DCS or the other Balancing Standards in real time. The policy should state that the BA performs an analysis to develop warning and alarm points for their operators for the reserves needed to meet BAL-001, BAL-002, and BAL-003. Having BAs provide this data to in real time to their Reliability Coordinators would add reliability value to the EEA and other EOP processes. Finally, a guidelines document on reserves approved by the NERC Operating Committee could be part of this policy] 3] Since there are now performance based BAAL and FRS in place, could we not actually simplify the current DCS? [Retain a cleaner version of the current R1, and a simpler R2 that requires presenting reserve values to BA and RC with appropriate alarm points] 4] The extent the remaining 693 directives have been met by other standards projects. [We believe BAAL addresses the Commission's concerns for detecting and responding to significant high or low frequency events, addresses the concern about performance to individual events, and is a performance-based double-confirmation of secondary and tertiary reserves] 5]For those requirements that are ultimately proposed, is there a way to keep them simple and easy to understand as opposed to being overly precise [For example, if there are exclusions in a requirement, rather than trying to calculate reserve recovery to the minute, exclude the hour when the situation occurs and the following hour(s), the number of hours determined by the extent contingency reserves were depleted)? We agree with comments submitted by the IRC-SRC and MRO-NSRF as applied to the current draft. The question is whether to continue to adjust the current draft or make sure we are creating a solution that is relatively simple to apply and provides reliability value. If we continue down the current path for the standard, we have two primary concerns. Our first concern is that the lowering of the threshold to 900 MW in the East, coupled with the proposed change from quarterly average performance to individual event performance, will increase customer costs for no discernable reduction in reliability risk. Both DCS performance (ALR statistics) and frequency performance (NERC Resources Subcommittee minutes) show frequency performance is more than adequate. As noted by Chairwoman LaFleur at NERC Board meetings, we should consider the reliability benefits of a standard vs. its costs. Costs will increase with the lower threshold for our customers. Because the interconnection is over-biased (ACE overstates resource loss) and dispatchers operate conservatively, our operators will likely deploy set-aside contingency reserves for any loss over 750 MW rather than wait to double-check the event size. This will likely add scores of contingency reserve deployment cases each year for situations that could likely be met by other on-line reserves. Finally, it should be noted that the frequency change from a 900 MW loss in the East is barely beyond the change from a Time Error Correction. Our recommendation is that the standard uses the lesser of 80% of MSSC or 1000 MW for the East. We also recommend that NERC retains the quarterly reporting. Individual cases of noncompliance can be tallied in the form to achieve the FERC directive, but we believe it is important that Enforcement assesses compliance base on the aggregate performance of the BA or RSG, not just spot observations. Our second major concern with the current posting for comment is that R2 goes beyond the original intent of the DCS. The reason there are no measures for this requirement in BAL-002-0 is that it was never intended to be a commodity standard. The predecessor to DCS was Policy 1, which had guidelines on operating reserves. The first DCS was one of NERC’s first performance-based standards and existed prior to the ERO. The intent was to retain the concept of the guide to plan to have a certain amount of reserves. The measures of success were to meet CPS and DCS. DCS’ intent was to respond quickly to all large events, with performance evaluated on events 80%-100% of MSSC. The intent of the 90 minute reserve replenishment was to get ready for future events (meaning you’d be held for compliance to the standard for events 90 minutes thereafter). Another reason for our concern is that this commodity requirement is being proposed without any data to support what actually is carried hour to hour across the Interconnections and the extent operators draw on these reserves to keep their system balanced. If R2 is retained as proposed, we believe that it should be a “positioning” requirement, not a zero-defect requirement. As proposed, either customer costs will increase or reliability will be negatively impacted. The only way to have more than 100% reserves all the time in normal operations is to carry well more than 100% reserves as a basis of operations or choose not to deploy reserves for non-reportable events and draw on frequency bias to keep reserves available. While the proposal provides some exclusions, the requirement should start on the basis that there will always be some variability and unforeseen non-consequential events that will require reserve deployment. If retained, we suggest R2 should require contingency reserves > 100% MSSC for 99% of all applicable hours. It should be noted that just because a BA has less than MSSC in one hour in four days, does not mean that it had zero reserves in that hour. Additionally, in a multi-BA Interconnection, the odds that the Interconnection would be deficient in Reserves with a 99% BA standard are astronomical. In a single-BA Interconnection there are backstops in the EOP and IRO standards. BAL standards are for normal operations. Other standards protect against events > N-1. Finally, we believe there should be a single quarterly report for R1 and R2. The R1 portion should be simplified to be very similar to today, to include reporting of events > MSSC (but not part of compliance evaluation). The quarterly R2 portion of the report should have the number of non-excluded hours the BA had reserves < MSSC and an identifier which hours were excludable under 2.1 through 2.6.

Group

SPP Standards Review Group

Robert Rhodes

Southwest Power Pool

BAL-002-2 Shouldn’t ‘transmission’ as used in the definition of Balancing Contingency Event in A.a.iii. and B. be capitalized? Several standards recently have foregone the Effective Date section in the standard and instead refer to the Implementation Plan for the specific implementation dates. Should that be considered here? Use lower case ‘requirement’ in the

3rd line of the Background material. Contingency Reserve should probably be capitalized in the 1st, 2nd and 4th paragraphs of the Rationale Box for Requirement R2. Delete the 's' on 'suites' in the 11th line of the 2nd paragraph of the Rationale Box for Requirement R2. Shouldn't 'load' be capitalized in the 4th paragraph of the Rationale Box for Requirement R2? Background Document Consistency is needed throughout the document in the capitalization of terms such as 'Transmission', 'Contingency Reserve', 'requirements', 'Transmission Line', 'Responsible Entity', 'Load', 'Real-time', 'energy deficient entities', 'event', 'field trials' and 'firm load'. In some situations, the SDT uses 'SDT' and in others it simply uses 'drafting team'. Be consistent throughout. Replace 'Balancing Authority or Reserve Sharing Group' with 'Balancing Authority (BA) or Reserve Sharing Group (RSG)' in the 9th line of the 3rd paragraph on Page 3. Subsequent uses of these terms should then be BA or RSG, respectively. Insert '(MSSC)' immediately following 'Most Severe Single Contingency' in the 2nd line of the 2nd paragraph on Page 4. Replace 'Standard' in the 6th line of the same paragraph with 'standards'. Replace 'the real-time operations' with 'Real-time operations' in the 1st line of the 1st paragraph under Balancing Contingency Event on Page 5. Replace 'requirement' with 'directive' in the last line of the 2nd paragraph under Balancing Contingency Event on Page 5. Replace the 3rd bullet at the top of Page 7 with the following: 'resolving the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) that requires the use of Contingency Reserves; and'. Replace 'requirements' with 'directives' in the 4th line of the 4th paragraph on Page 9. Replace 'suites' with 'suite' in the 1st line in the 1st paragraph at the top of Page 10. The SDT is to be commended for the improved clarity in the examples in Attachment 2. The reference sited in the last line of the 2nd paragraph on Page 34 (Footnote 5) is not attached. It's referenced in Footnote 5. There is no Footnote 3 as referenced in the 3rd line of the paragraph under Control Performance Standards (CPS1) on Page 34. CR Form 1 In cell A15 of the Read Me tab, use lower case 'it'. In cell A1 of the Exemption tab, replace 'Exemp' with 'Exempt'. In cells A10 and A16 of the Description tab, © appears instead of the intended (c). Thanks Microsoft. In cell A11 of the Entry Instructions tab, insert 'with' between 'associated' and 'subsequent'. In cell A4 of the Calculator tab, insert 'the' between 'Enter' and 'name'.
Group
Duke Energy
Colby Bellville
Duke Energy
General Comments: Duke Energy would like to take the opportunity to offer comment on the overall project concerning BAL-002-2 in conjunction with the recent FERC NOPR issued on November 20, 2014. FERC issued a NOPR proposing the approval of the BAL-001-2 standard (Real Power Balancing Control Performance). FERC commented in its NOPR that further revisions to the BAL-002 standard should take into consideration, the impact the revisions may have on the Balancing Authority ACE Limit (BAAL) in BAL-001-2. Duke Energy agrees with the Commission that the potential impact that compliance with BAL-002 may have on BAAL should be taken into consideration during further modifications to BAL-002, and suggests that

this project be tabled until the final order issuing the approval of BAL-001-2 has been handed down by FERC. Balancing Contingency Event: Duke Energy would like to re-state its concerns with the proposed definition of Balancing Contingency Event. Originally, we stated that we sought clarification on item B of the Balancing Contingency Event (BCE) definition. A BCE should be predicated on a deviation in Area Control Error (ACE) . As written, we are unclear why item B is even part of the definition because we believe Item B is redundant with item A.a.ii. We fail to see the additional clarity that Item B provides, and could see where questions could arise regarding the differences between the two items in the future. Background: In the revised background section of the proposed BAL-002-2, the section alludes to frequency management, however, we fail to see any requirement in this standard pertaining to frequency management. R1: We would like to offer our previous comment on this requirement for the drafting team's consideration. Duke Energy suggests the following revision to R1.2: "1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert under which Contingency Reserves have been utilized to serve load." We believe the intent of the SDT was for the Responsible Entity to be exempt from compliance with R1 during those instances where Contingency Reserves are utilized to serve load. Duke Energy requests further clarification on what is meant by the reference to activate Contingency Reserves under an Energy Emergency Alert (EEA). R1 Rationale: If the SDT's intent is to eliminate any potential overlap with other standards, this will not be the case once the BAAL is in place. If BAL-001-2 is approved, there will be another standard driving a BA to take corrective action when frequency is hurting. Again, we caution the SDT that moving forward with the BAL-002-2 project without taking into consideration the BAAL, could result in conflicting standards. In addition, we believe that there are situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency. For example, as the Disturbance Control Standard ("DCS") under BAL-002 is measured event-by-event, a Balancing Authority is required to return its ACE to zero with 15-minutes after a Reportable Disturbance (or back to its pre-Disturbance ACE value if that value was negative). Such a response in the future may be a problem if the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response required by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2. If a generation resource was lost in the middle of the night during a period of minimum load concerns, numerous available generation resources, and high Interconnection frequency, BAAL would drive the Balancing Authority to take appropriate action over a reasonable timeframe. DCS would not consider any of these factors but would require the Balancing Authority to strictly comply. This strict compliance with BAL-002 could have a detrimental impact on Interconnection frequency. R2: Duke Energy requests further clarification from the drafting team on whether its intent was for the standard to be worded in such a manner to allow for the waiving of immediate restoration of reserves. Is it the SDT's intent to afford an entity the opportunity to wait for a period of 90 minutes, before requiring the restoration of reserves to take place? Also, Duke Energy suggests a re-ordering of the sub-requirements for R2. Sub-requirements 2.4 and 2.5 should be first and second on the list of sub-requirements based on the reasoning that they would be the most common instances. Regarding sub-requirement 2.6, we feel that clarifications are needed. As written

currently, it is unclear whether an entity has to actually shed load for 2.6 to apply, or if you have to just be prepared to do so. There are concerns that requiring compliance documentation to demonstrate that you were prepared to take some action, even though said action never took place, could be considered onerous. Lastly, upon our review, it could be argued that some of the sub-requirements appear to mirror closely responsibilities that are already present in EOP-002. We suggest that the SDT consider delaying implementation of BAL-002-2 so that it becomes effective after EOP-011-1.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
LG&E and KU Energy, LLC
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. The PPL NERC Registered Affiliates support the comments provided by PJM. In addition, we submit the following comments: It is not clear how the compliance exemptions in R1.2 and R2.6 for a Responsible Entity experiencing an EEA would apply to a RSG. Since an RSG cannot request the RC to declare an EEA , it appears the RSG would be required to maintain MSSC level reserves regardless of the EEA status of its member BAs. It also appears the RSG could be found non-compliant with both R1.2 and R2.6 simultaneousl. We suggest that while a member of a RSG is in an EEA, its MSSC and Contingency Reserve Requirement (the member BA's reserve obligation to the RSG) are removed from the RSG. The reconfigured RSG would continue to maintain the RSG based on the new MSSC and the revised assignment of CRR among the non-EEA members. The RSG would remain in this configuration for the duration of the member BA's EEA. Assigning a Medium VRF to both R1 and R2 is not appropriate – the reliability impact of not having the required amount of reserves does not seem comparable to the reliability impact of not recovering ACE after a reportable BCE. The VRF for R2 should be lower than R1. If R2 cannot be revised as suggested by PJM, an alternative to the average Clock Hour measurement period should be provided. If reserves dip below the MSSC late in a Clock Hour, it is doubtful if a RE could act in time to resolve the shortfall. Also, what is the reliability benefit of an RE acting to increase its reserves if the shortfall occurs earlier in the hour? It doesn't seem the average Clock Hour measurement period provides an RE much flexibility in complying with R2 nor does it improve BES reliability. A rolling hourly average or multi-Clock Hour average would be an improvement. BAL-002-2 directly applies only to BAs and Reserve Sharing Groups, but it states in the definition of Contingency Reserve that the capacity mandated, "may be provided by resources such as Demand-Side Management (DSM), Interruptible Load and unloaded generation." That is, BAs can fulfill their BAL-002-2 obligations only by imposing demands on these other parties, and we would like to know up-front what they will be. This concern is heightened by the addition (effective 4/1/2015) of the

expression, “and discourage response withdrawal through secondary control systems,” to the NERC Glossary definition of Frequency Bias Setting. This change echoes the statement, “appropriate outer-loop controls (distributed controls) settings to avoid primary frequency response withdrawal,” in the NERC Resource Subcommittee’s 2013 Eastern Interconnection Frequency Initiative Whitepaper,” and “Related outer-loop controls within the DCS, as well as applicable generating unit or plant controls, should be set to avoid early withdrawal of primary frequency response,” in NERC’s 2/5/2015 Industry Advisory, Generator Governor Frequency Response.” Implementation of appropriate governor time delays and droop settings constitutes a well-defined and technologically justified form of GO involvement in frequency response improvement, but the term “response withdrawal” is vague and could cause BAL-002-2 to be misconstrued as authorizing BAs to demand new, frequency response-enhancing services from GOs as a regulatory requirement rather than obtaining them through market mechanisms.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1 - ReliabilityFirst suggests using the word “shall” instead of “will” to make mandatory the use of the noted CR Form 1. The term “shall” indicates a duty on the subject and is used throughout the NERC Standards in this manner; in this case the responsible entity has a duty to use CR Form 1, so “shall” is the more appropriate term. ReliabilityFirst recommends attaching it to the standards along with the following change for consideration: “The Responsible Entity shall document all Reportable Balancing Contingency Events using Attachment 1 - CR Form 1.” 2. Measure M2 - The newly included second paragraph within Measure M2 reads more as an exception to the requirement and does not belong as a measure. It appears to be guidance to an auditor and should more appropriately be placed in an RSAW. Furthermore, ReliabilityFirst does not want to encourage missing data as a reason for not performing the calculation and believes any or as many valid samples of the Contingency Reserve should be included in the clock hour and should not be excluded from the evaluation. ReliabilityFirst recommends completely removing the second paragraph within Measure M2 from the standard.
Group
Associated Electric Cooperative, Inc.
Phillip Hart
AECI
AECI respectfully requests that the SDT further consider modifying the Contingency Event Recovery Period to 30 minutes, or provide empirical evidence that demonstrates a risk to reliability exists when a Responsible Entity exceeds 15 minutes before recovering their ACE to the pre-disturbance level. Absent a risk to reliability when exceeding 15 minutes, the use of

30 minutes for the Contingency Event Recovery Period would more closely align with other reliability standards requirements that relate to operation of the BES during events, specifically the amount of time allowed for an entity to exceed an IROL.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Southern Company Operations Compliance
In regards to R2.6: In an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. Southern agrees that a BA should not be required to maintain Contingency Reserves during an applicable Energy Emergency Alert level (for Southern that would be an EEA3). Our concern is with how the following sentence is phrased "For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared." We recommend a different approach so that it reads, "For this exemption to apply, the deficient BA must be able to execute interruption of Firm Load to restore ACE within the Contingency Event Recovery Period timeframe". The rationale behind this change is if a deficient BA can recover ACE within Contingency Event Recovery Period via load shed this should be an acceptable practice but they must have the ability to execute completely this action within the Contingency Event Recovery Period timeframe (e.g. 15 minutes). Southern agrees with the drafting team that in an EEA3 a BA should be able to consider load shed as a viable practice to maintain ACE and not be required to re-establish Contingency Reserves by shedding load pre-contingency. The current way the Measure is worded supports this purposed change.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Agree
Group
Peak Reliability
Jared Shakespeare
Peak Reliability

General: BAL standards should be developed as a group and not individually. R1.2: “A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.” EOP-002-3.1 speaks to the RC initiating/declaring but not approving an Energy Emergency Alert. It can be argued that parameters are in place to make a decision on approval but nevertheless there is no mention of approvals nor defined approval processes within the standard. Suggestion is to revise from “approved” to “initiated/declared” to remain consistent with EOP-002-3.1. R2: Peak is concerned that using an average clock hour might allow entities to take advantage. For example, if an entity is deficient the first 30 minutes but sufficient the second 30 minutes, the average clock hour would be met but the first 30 minutes would be in an unreliable state.
Individual
Catherine Wesley
PJM Interconnection
1. Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution. Comments: PJM appreciates and recognizes the work of the SDT as reflected in the present posting of the proposed BAL-002-2. PJM strongly urges the SDT to incorporate the following changes. R1 Suggested changes: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Eevent, or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Eventevent. 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved declared Energy Emergency Alert Level under which Contingency Reserves have been activated or depleted below reserve requirements. 1.3. Requirement R1 (in its entirety) does not apply: • (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or • (ii) after multiple Balancing Contingency Events and/or Contingency events that are not Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period, or • (iii) when the Responsible Entity is operating under the conditions described in R2, in its entirety. R1 Discussion: PJM views it as necessary to include the MW losses associated with units that may ramp down or be derated which also result in a loss of output or capacity. CR Form 1 needs to be modified to account for the suggested changes in R1. R2 Suggested changes: R2. The Responsible Entity shall

develop and maintain an Operating Plan to procure Contingency Reserve capacity for each hour greater than or equal to its Most Severe Single Contingency for that hour. R2 Discussion: PJM urges incorporation of our suggested revision to R2. PJM would be supportive of a standard that incorporated our proposed revision. This revision recognizes that the procurement of Contingency Reserves is accomplished in the Operation Planning time horizon and that R2 as presently drafted is overly prescriptive. R2.6 Suggested Changes: Should the presently drafted R2 and associated sub-requirements remain in the standard, PJM believes R2.6 is not acceptable in its present language. A necessary revision would be as follows: R2.6. in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve. available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. R2.6 Discussion: Load shedding plans are adequately addressed in the EOP standards. Requirement R2.6 as proposed is a distraction for the System Operator that has no positive impact on reliability. The requirement as written requires that Firm Load be shed to replace a shortfall of Contingency reserves. Why would an entity shed load to maintain reserves when shedding load via SCADA can be accomplished quicker than loading Contingency Reserves?
Group
ACES Standards Collaborators
Jason Marshall
ACES
(1) The Most Severe Single Contingency definition and applicability section 4.1.1.1 should be modified to reflect that the standard simply applies to a BA or RSG by striking “that is not participating as a member of a RSG at the time of the event”. This language may conflict with existing RSG contracts. Furthermore, it is a registration issue on whether the standard applies to the BA or RSG in these situations. When the RSG registers with NERC, NERC will typically review the contract to understand how the RSG is formed. If the standard should apply to the BA in certain situations and the RSG in others, this should be documented in a coordinated functional registration, not in a standards definition or applicability section. What does it even mean to be in “active status” under applicability section 4.1.1.1? (2) Please strike the last sentence of the Reportable Balancing Contingency Event. It is administrative in nature and should be handled through compliance monitoring processes. If NERC wants to know if an entity has modified its reportable threshold, they have a myriad of compliance monitoring processes and tools to gather this information. It does not need to be documented in a glossary definition. Furthermore, it is not really a definition but rather an explanation and therefore, does not belong in the definition. (3) We continue to believe that the thresholds defined in the Reportable Balancing Contingency Event are arbitrary. We ask that the drafting team provide a technical basis for the values instead of the existing explanation in the Background document. While we understand that the drafting team reviewed some data,

there are uncertainties regarding how values were identified from the data and then another value was selected. (4) We are confused about the “one-minute interval that defines a Balancing Contingency Event” language in the Contingency Event Recovery Period definition. We can find no reference to “one-minute” in the Balancing Contingency Event definition. There is, however, such a reference in the Reportable Balancing Contingency Event. Furthermore, the one-minute interval really does not define the event but rather pre-disturbance level before the start of the event. The language in the Contingency Event Recovery Period needs to be cleaned up to reflect this information. (5) We disagree with the definition of Contingency Reserve. The definition should be modified to simply reflect that Contingency Reserve Is unloaded on-line generation and quick start off-line generation capable of being dispatched in 15 minutes. The current definition may limit the use of Contingency Reserve and may omit off-line quick start generation since unloaded generation usually refers to on-line generators. (6) Reportable Area Control Error in the Rationale box for R1 should be changed to Reporting ACE to match the NERC Glossary. (7) The insertion of the “Reliability Coordinator approved” in Part 1.2 creates additional confusion by implying that an EEA can be issued without RC approval. An EEA cannot be issued without RC approval. Thus, this language is superfluous, only adds ambiguity and confusion to the part and should be struck. (8) Although, we do not oppose the use of CR Form 1, Part 1.1 should be struck as it is administrative in nature. A violation of Part 1.1 could never result in a harm to reliability. If an entity were to report the data in another format, reliability would not be harmed. If reliability cannot be harmed then a standard should not compel the action (in this case, specific use of a reporting form). Use of a CR Form 1 can and should be handled through NERC compliance monitoring processes as NERC and the Regional Entities do with other reporting formats and data collection methods. Use of CR Form 1 is already documented in the RSAW which should be sufficient. (9) While we appreciate that the drafting team did attempt to document other acceptable uses of Contingency Reserve in R2 that would not violate the requirement, we fundamentally disagree with the arbitrary selection of 90 minutes as a limit on the use of Contingency Reserve. Why should use of Contingency Reserve be limited to 90 minutes for an Energy Emergency? An Energy Emergency could last several hours and BA would be forced to either violate the requirement or shed load to avoid a compliance requirement. Neither is a good outcome. Rather, we suggest the 90 minute period should be dropped in Parts 2.1, 2.2, and 2.3. We particularly see this as an issue for Part 2.2. If an RC were to issue an Operating Instruction to use Contingency Reserve to resolve an EEA to avoid shedding load, why should this higher level authority not be able to instruct the BA to exceed the 90 minutes? The fact that Contingency Reserve may be used for longer than 90 is even documented in the second to last paragraph on page 36 of the background document. (10) We disagree with the arbitrary selection of five minutes in Part 2.6 for the exemption to apply. We believe the five minutes is arbitrary and language is ambiguous which will only lead to inconsistent compliance outcomes. What would be considered preparations? Sending techs to the stations? Arming loading shedding schemes? Thinking about it? There needs additional clarification in the standard. (11) We disagree with the move from quarterly reporting to exception reporting. Today, compliance is assessed on a quarterly basis. This standard appears to require a Responsible Entity to issue a self-report anytime it does not recover

100% from a reportable a Reportable Balancing Contingency Event without any basis identified for the change. This will serve to increase a Responsible Entities compliance costs without any commensurate benefit to reliability. Furthermore, it will eliminate a data source that NERC uses for its annual state of reliability report which will be detrimental to the report. (12) In Measure 2, we suggest adding a clause to the first bullet that Contingency Reserve must meet or exceed the required amount "unless one of the exceptions from R2 is met". (13) In Measure 2, we are confused by the language "excluded by rule in Requirement R2". Does this mean excluded by Parts 2.1 through 2.6? If so, change the language to "excluded by Parts 2.1, 2.2, 2.3, 2.4, 2.5 or 2.6". (14) The VSLs for Requirement R2 should be modified to state that Responsible Entity did have less than the required amount of Contingency Reserve "and did not meet one of the exceptions in Parts 2.1 through 2.6". (15) We are concerned that the requirement formatting of the exceptions in Part 2.1 through 2.6 are not consistent with the informational filing NERC submitted to FERC several years ago regarding the use of bullets and parts in place of sub-requirements. In that filing, NERC stated that numbered lists or "Parts" would be used when all "Parts" must be met and "bullets" would be used when there are exceptions. To qualify for an exception, only one of the Parts 2.1-2.6 should be met not all. Yet, use of a numbered list implies that all exceptions must be met. The formatting needs to be modified to bullets instead of a numbered list.
Individual
Christina Bigelow
ERCOT
ISO/RTO Council Standards Review Committee
ERCOT commends the drafting team on their efforts to improve BAL-002-2. However, it has concerns and recommendations regarding the proposed modifications. These concerns and recommendations are described below by Requirement. Proposed revisions are italicized. 1. Definitions – ERCOT reiterates its previous comments regarding the Reportable Balancing Contingency Event thresholds contained within the definition of a Reportable Balancing Contingency Event. ERCOT believes that the introduction of various, differing thresholds creates unnecessary complexity and would propose a 1000 MW threshold for its interconnection as such threshold aligns with the current practice. Further, ERCOT reports other, smaller events to NERC and its Regional Entity through different mechanisms and, therefore, with differing reporting thresholds, the same event can be reported to NERC multiple times under different requirements. Accordingly, since the threshold limits relate only to reporting and associated documentation, ERCOT respectfully submits that lowering the reportable event thresholds does not provide any benefit to reliability. 2. Requirement R1 – Recommend modifying the addition (Reliability Coordinator Approved) to Reliability Coordinator Issued. 3. Requirement R1.2 and Requirement R1.3 – ERCOT recommends the consolidation of R1.2 and R1.3 and additional revisions as follows: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when: • It is experiencing a Reliability Coordinator issued Energy Emergency Alert Level under which Contingency Reserves have been activated or depleted. • It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency • It has experienced multiple Balancing Contingency Events

for which the combined MW loss exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. ERCOT recommends modifications to subpart 1 regarding the depletion of contingency reserves because contingencies that deplete reserves can occur without formal “activation” of reserves and without a “sudden” or triggering event. Thus, it respectfully suggests that the requirement should be modified to ensure that acknowledgment of such reserve depletion. ERCOT further recommends revision to subpart 1 because partially loaded generators may experience contingencies that remove MW from the BA, which may reduce the availability of reserves maintained by such resources as headroom. In such a circumstance, it is possible to have multiple contingencies where the MW loss is less than the MSSC, but that result in significant or complete reserve depletion for the BA. Accordingly, ERCOT recommends that subpart 3 be clarified to ensure that the loss to which the subpart would be applicable is clear and unambiguous. By accounting for overall MW of loss, not the magnitude of capacity loss, the applicability of Subpart 3 would be objective and easily discerned. 4. Requirement R2 –ERCOT respectfully submits that, as proposed, Requirement R2 would result in the unnecessary diversion of attention and resources during real-time operations to ensuring that data recordation and documentation occurred – rather than the performance of activities that are more directly associated with sustaining the reliability of the Bulk Electric System, e.g., contingency reserve mix, monitoring, deployments, etc. Accordingly, ERCOT respectfully suggests the following alternative revisions, which it believes more closely aligns with the Commission’s directives: R2. The Responsible Entity shall plan to procure Contingency Reserve greater than or equal to its Most Severe Single Contingency, except during one or more of the following periods when the Responsible Entity is: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] 2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or 2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or 2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or 2.4 in a Contingency Reserve Restoration Period; and/or 2.5 in a Contingency Event Recovery Period; and/or 2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. Measure 2 could then be modified as follows: Compliance may be achieved by demonstrating that: • The Balancing Authority’s Operating Procedures require procurement of Contingency Reserve amounts that meet or exceed the Contingency Reserve required to respond to its Most Severe Single Contingency; or, • Contingency Reserve has been restored to the required Contingency Reserve levels within the specified period; or, • the sum of the Contingency Reserve and Firm Load available as a substitute for unavailable Contingency Reserve reaches the required Contingency

Reserve level within the specified period; Failure of the Balancing Authority to procure adequate Contingency Reserve to respond to its MSSC and/or recover the required Contingency Reserve level within the time periods prescribed would be considered an exception and should be reported quarterly. ERCOT suggests this alternative because the directive being addressed required development of a continent wide contingency reserve policy, but did not require or prescribe tracking or reporting obligations. The proposed modifications appear to not only address a proposed reserve policy, but appear to also be revising the current quarterly reporting and prescribing an hourly tracking and recordation, actions and obligations for which ERCOT has been unable to identify an associated directive. Such additions will likely have unintended consequences in how Reserve Sharing Groups (RSG) will operate. In particular, the failure or delay of a contingency resource start can result in recovery performance that is assigned a very low score for that single event, even where recovery is only a minute or two late. Such outcome would be an inaccurate indicator of the overall success of the recovery, the overall recovery performance, and the Responsible Entity's efforts to recover. Further, there are RSGs whose purpose is to mitigate such risk by deploying reserves for much smaller events, helping reliability through quick recovery from smaller events, faster replenishment of reserves, and opportunity for operators to gain necessary experience regarding reserve deployment. Should each recovery event become individually sanctionable, RSGs will likely modify their rules to increase their reportable threshold to the interconnection minimum, which would reduce the net benefits to grid reliability discussed above. Additionally, the current quarterly reporting has provided an important data source that is used for NERC's RAPA group and the State of Reliability Report: http://www.nerc.com/pa/RAPA/ri/Pages/DCSEvents.aspx. The transition away from quarterly reporting to only exception reporting will eliminate that data source and reduce overall visibility. To facilitate the identification of exceptions while maintaining the value and benefits associated with quarterly reporting, ERCOT recommends that there be a single quarterly report for all data collected. In such a report, the Requirement R1 portion would be very similar to the current reporting form with an additional portion where instances of reserve amounts that were less than the MSSC during the quarter could be reported. Such coordinated reporting would allow both the ERO and the industry to evaluate reserve and contingency data concurrently, providing the opportunity to identify any trends and/or dependencies. ERCOT respectfully submits that the requirement to plan for and procure reserves greater than or equal to a BA's MSSC is an appropriate continent-wide contingency reserve policy and that such policy, when considered in coordination with obligations set forth within other approved reliability standards such as EOP-011-1 (Requirement R6), IRO-005-3.1 (Requirement R2), and TOP-002-2.1b (Requirements R5 – R8) are more than adequate to ensure reliability. Further, ERCOT would suggest that hourly calculation and/or demonstration of reserve amounts is: (1) not necessary when reserve requirements are considered in pari materia with other reliability standards obligations of BAs as described above, (2) unduly burdensome, and (3) a threat to reliability due to the diversion of resources that would be necessary to sustain compliance. Quarterly reporting of Reportable Balancing Contingency Events along with the reporting of reserve amounts less than a BA's MSSC are more than sufficient for both the ERO and responsible BAs to identify and address

contingency reserve issues that would threaten reliability. Hence, requiring BAs to provide documentation of contingency reserves averaged over a clock hour is an onerous, purely administrative obligation that elevates documentation over reliability. Thus, ERCOT recommends that Requirement R2 be revised as set forth above. ERCOT thanks you for the opportunity to comment upon the proposed Revisions to BAL-002-2 and respectfully suggests that, as NERC continues its effort to move away from zero defect standards, Requirement R2 be revised as recommended above to support that concept. Should the ERO wish to provide additional guidance regarding the mix or management of Contingency Reserves, it should consider the development and publication of a Reliability Guideline.
Group
Bonneville Power Administration
Andrea Jessup
Transmission Reliability Standards Group
BPA is in agreement with the proposed standard, however, believes there should be a clarifying comment in requirement R1. In R1, following both sub-bullets of R1, BPA would like to state: “For all subsequent events that occur during the initial Contingency Event Recovery Period, the Pre-Reporting Contingency Event ACE Value for that initial event must be used for the subsequent event(s).” Finally, BPA proposes that R2 2.6 spells out that it only pertains to an EEA3. The reason for this is that exemption only applies to EEA level 3 in EOP-011-1 Emergency Operations. In that new standard, EEA 3 is defined, in part, as a situation where “The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.” EEA 2 language clearly states that while a BA can no longer meet all of its expected energy requirements: “An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.”
Individual
Richard Vine
California ISO
Agree
ISO/RTO Council Standards Review Committee
Group
ISO/RTO Council Standards Review Committee
Charles Yeung
SPP
1. The SRC generally supports R1. For clarity, and to address a concern that events that do not sudden as defined in the term “Balancing Contingency Event” (such as ramping, derating, etc.) are excluded from the recovery consideration, the SRC suggests the following minor clarification to R1 for consideration: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: • Zero,

(if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Contingency event that occurs shall reduce the required recovery: beginning at the time of, and by the magnitude of, each individual Contingency event, or, • It's Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Contingency event that occurs shall reduce the required recovery: beginning at the time of, and by the magnitude of, each individual Contingency event. (i.e., strike out (i) and (ii)) We further suggest Part 1.2 be revised to read: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when: • It is experiencing a Reliability Coordinator issued Energy Emergency Alert Level under which Contingency Reserves have been activated or deleted. • It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency. • It has experienced multiple Balancing Contingency Events and/or Contingency events that are not Balancing Contingency Events for which the combined MW loss exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. 2. In our previous comments, the SRC stated that it found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met the requirement in R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. Note: ERCOT does not support this comment. 3. In addition, the proposed R2 has the following potential adverse consequences: • An increase in reserves in order to maintain an amount over-and-above that required by the standard to meet non-DCS operational events, therefore, costing the rate payers additional monies for no increase in reliability (Note: IESO does not support this comment); • Operators not deploying reserves when needed for reliability in order to meet compliance with this requirement, which could be detrimental to reliability; and/or • Entities shedding firm customer load to maintain reserves to meet compliance with this requirement, which, again, is not the right action to take for reliability. 4. We understand that the intent of the proposed R2 is to require a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 with the following: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering other events that may reduce this amount. We believe this together with the recovery provision in R1 and the provision in Requirement R6 and Attachment 1 of EOP-011-1 would collectively take care of many of the conditions listed in the proposed Requirement R2 including active monitoring of the amount of reserve to meet the Contingency Reserve requirement. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted items may be added under Part 1.3 in R1: • When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) Note: ERCOT does not support this comment.

Additional Comments

Joe Spencer/SERC/OC Review Group

We have the following questions and concerns with the language in the Applicability subsections for 4.1. Section 4.1.1.1 is problematic in that it states that the RSG is the RE when BA's are in 'active status'. Active status is subjective and likely not a defined term in governing RSG agreements. Additionally, the definition cannot be applied consistently to both R1 and R2. Please consider the following examples where a BA is assumed to be actively maintaining its reserve allocation for the RSG.   o A BA experiences a Reportable Event in which it recovers ACE and reserves in accordance with R1 without requesting assistance from the RSG members. The BA is the RE even though it is in 'active status' in the RSG.   o For R2 compliance purposes, as long as the BA is actively maintaining its allocation of reserves in accordance with the governing RSG agreement, the RSG is the RE.   o Applicability for R2 is further complicated when the BA may participate in an RSG for only part of its footprint and maintains its allocation for the RSG while also maintaining additional reserves for the MSSC in the overall balancing area. In this example, both the BA and the RSG are may be RE's. We believe that to resolve these issues, the BA versus RSG applicability should be moved to the requirements themselves. The SDT could also consider explicitly stating that a BA is compliant under R2 when it maintains the average hourly reserves at least equal to its reserve allocation under the terms of the governing RSG agreement.R1 - clarity needs to be added to phase "(i) beginning at the time of" to explain how this phrase applies. 2. We recommend the following change to the proposed language of R1.1.R1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 [or an acceptable alternative.]â€ƒ3. We recommend the following change to the proposed language of R1.2.R1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.]R1.2 Comment: The proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet to be approved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R1 compliance exemption, making the BA even less able to meet its reserve requirements.Further, if a BA declares an EEA, indicating that it is unable to meet reserve requirements, and subsequently deploys some of its reserves to meet increased load does this constitute a deployment of contingency reserves under R1.2 and what evidence does the BA provide to demonstrate compliance?4. We recommend the following changes to the proposed language of R2.R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] o a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing

Contingency Events. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or o response to a Reliability Directive; and/or o a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or o an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.]R2 Comment: As stated in the comments for R1.2, the proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet unapproved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R2 compliance exemption, making the BA even less able to meet its reserve requirements.Additionally, absent the suggested language in the first bullet, a BA may receive a Reliability Directive from its RC (see IRO-001 R8) to deploy Contingency Reserves to mitigate a condition or event that is having an adverse reliability impact on the BES, but be non-compliant under R2 for following that directive.We believe that R2, as currently proposed, is unnecessary to satisfy the directive in FERC Order 693 to develop "a continent-wide contingency reserve policy", as this was accomplished with the development of Reliability Guideline: Operating Reserve Management that was approved by the NERC Operating Committee in October 2013. If, however, the SDT decides that it is necessary to keep the commodity obligations currently proposed in R2, we believe that the suggested R2 changes above will reduce unintended adverse reliability consequences while further reinforcing satisfaction of the directive. Additional Comments:The SDT has failed to demonstrate a performance need, in the form of negative historical trends for DCS recovery or compliance, for the proposed changes. Significant negative consequences of the proposed standard include but are not limited to:1) The proposed language moves this project from being a performance based standard to a commodity obligation.2) Creates a daunting and unnecessary administrative burden in tracking the commodity obligations set forth in Requirement 2. For example, the following are just a few of the evidence requirements in the RSAW: a. R2 requires dated documentation that demonstrates that hourly Contingency Reserves were at least equal to hourly MSSC. In a three year audit period that is 26,280 one hour intervals! b. Both R1 & R2 require dated documentation for all Reportable Balancing Contingency Events that occur when an EEA and Contingency Reserves have been activated. When an RE declares an EEA2 or EEA3, under the current TOP standard, they are declaring that they may be unable to meet required reserve requirements. When the load increases after the EEA has been declared and units that were previously providing CR are then dispatched higher to balance the increased load, does that constitute deploying CR? What evidence does the RE provide? 3) Increased customer costs absent a demonstrated reliability need as BA's are incented to purchase additional contingency reserves beyond that needed to recover from the loss of MSSC.4) Increased frequency variation as BA's are incented to change generation dispatch at the top of each hour to meet the R2 commodity obligation.5) Increased SOL & IROL exceedance durations as BA's are reluctant to deploy reserves to mitigate.6) As stated above, this standard creates a compliance trap for System Operators who may have to choose between activating reserves and shedding load for non-Reportable events OR following Reliability Directives under IRO-001 and maintaining reserves under BAL-002 R2.7) An increase in BAAL excursion minutes & frequency variation as BA's are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. 8) Provides a disincentive for a BA to assist its neighbor when a formal RSG Agreement is not in effect.9) The Severe VSL omits the "from a Reportable Balancing Contingency Event" language that is included in the Lower, Moderate, & High VSLs. We believe this omission was an oversight.10) The Background Document states on page 4 that “BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency” while R2 discourages the System Operator from using one of the important tools for accomplishing that task; Contingency Reserves.11) The Background Document states on page 5 that “FERC Order 693 (at 355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation”. Order 693 (at P355) directs the ERO to “define a significant deviation and a reportable event”. This misstatement in the Background Document is significant and should be corrected.12) The Background Document states on page 6 that “the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3”. This statement is inconsistent with the current posting.13) The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled “Frequency Events Loss MW Statistics”. a. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. b. The data appears to show loss of generation and loss of load events in the same samples. If the intent is to show statistical correlation between the MW size of an event and magnitude of frequency deviation then loss of generation and loss of load events should be separated. c. Last step in example on Page 22 of the redline version, the -200 MW appears to be incorrect. The required ACE Recovery should be -600 MW. The comments expressed herein represent a consensus of the views of the above-named members of the SERC OC Review Group only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

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Although the standard does not directly affect Consumers Energy, after reviewing the purposed standard and comments, I feel the intended goal to eliminate the ambiguities and questions associated with the existing standard has not been met. The new definitions and standard language confuse and complicate the issues.