Individual or group. (28 Responses)
Name (13 Responses)
Organization (13 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Contact Organization (15 Responses)
Question 1 (28 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
1. Recommend the following change to the definition of a Balancing Contingency Event: Balancing Contingency Event: 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. A. Sudden loss of generation: a. Due to i. Unit tripping, ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or iii. Sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE. B. Sudden loss of an import, due to forced outage of transmission equipment or the curtailment of Interchange Transaction(s) due to initiation of a TLR procedure that causes an unexpected imbalance between generation and load on the Interconnection. C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE. 2. Recommend the following change to the proposed language of Part 1.1: 1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 or an acceptable alternative. 3. Recommend the following change to the proposed language of Part 1.2: 1.2. 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. 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 a R1 compliance exemption, making the BA even less able to meet its reserve requirements. 4. 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] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events or in response to a Reliability Directive. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • 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. As was stated in the comments for Part 1.2, 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 the proposed language changes to Requirement 2 satisfy the directive in FERC Order 693 to develop "a continent-wide contingency reserve policy". 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) Increased customer costs absent a demonstrated reliability need as BA's have an incentive to purchase additional contingency reserves beyond that needed to recover from the loss of MSSC. 3) Increased frequency variation as BA's have an incentive to change generation dispatch at the top of each hour to meet the R2 commodity obligation. 4) Increased SOL and IROL exceedance durations as BA's are reluctant to deploy reserves to mitigate. 5) Reduced Operating Reserves during high demand periods as entities are encouraged to activate reserves during an EEA due to the proposed language in Part 1.2 and R2. 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 and frequency variation as BA's are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. 8) Creates industry confusion regarding the proposed changes to EOP—011 Attachment 1 (at the request of the BARC SDT) by implying that maintaining reserves takes priority over shedding load. 9) Creates an unnecessary administrative burden in tracking the commodity requirements of R2. 10) Provides a disincentive for a BA to assist its neighbor when a formal RSG is not present. 11) As previously noted, we believe that the definition of a BCE needs to include "the curtailment of Interchange Transaction(s) due to initiation of a TLR procedure", else the System Operator may find him/herself in a position of having to choose between activating reserves or shedding load. 12) 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. 13) 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. 14) 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. 15) 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 must be separated.
Group
Florida Power & Light
Mike O'Neil
Florida Power & Light
Section - Definitions of Terms Used in Standard Balancing Contingency Event: 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. B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection. On B, sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection: There are other mechanisms to handle sudden loss of import and sudden unplanned outage; this should not be in this standard. The IROL standards require operators to take action to prevent reliability issues including re-dispatch and shed load. Having FRSG groups activate Contingency Reserves could have unintended consequences. Examples: In the event that multiple BAs are being affected by the reduction of the import; if all BAs call for reserves the overall recovery will be delayed since the BAs will be importing and exporting power. If TLR is used to curtail import due to reliability issue and the transaction affected was between two or more members of the same FRSG group, the call for reserves will negate the loading relief of the TLR. On C, sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE: This should not be part of BAL-002. Restoration of load should be done in a controlled manner

and if a BA does not have sufficient generation to restore firm load, then the EEA process should be followed.
Group
Arizona Public Service
Janet Smith
Arizona Public Service Company
The additional language added in the applicability section that states: “the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated” is restated within R1.2. AZPS believes that this duplication is unnecessary and that one of the locations should be removed. Additionally, it is not entirely clear what qualifies as use of Contingency Reserve for Contingencies that are not Balancing Authority Contingencies. AZPS would like to request the SDT provide an example or additional clarity to the first bullet in R2 that states, “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”.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Madison Gas & Electric
1. We recommend the following change to the definition of a Balancing Contingency Event. Balancing Contingency Event: 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. A. Sudden loss of generation: a. Due to i. Unit tripping, ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity’s electric system, or iii. Sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity’s ACE; B. Sudden loss of an import, due to forced outage of transmission equipment or the curtailment of Interchange Transaction(s) due to initiation of a TLR procedure that causes an unexpected imbalance between generation and load on the Interconnection. C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity’s ACE. 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. 3. 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. 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] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events or in response to a Reliability Directive. This required restoration begins when the Responsible Entity’s Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • 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 the proposed language changes to Requirement 2 satisfy the directive in FERC Order 693 to develop "a continent-wide contingency reserve policy". 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) 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. 3) Increased frequency variation as BA's are incented to change generation dispatch at the top of each hour to meet the R2 commodity obligation. 4) Increased SOL & IROL exceedance durations as BA's are reluctant to deploy reserves to mitigate. 5) Reduced Operating Reserves during high demand periods as entities are encouraged to activate reserves during an EEA due to the proposed language in R1.2 & R2. 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) Creates industry confusion regarding the proposed changes to EOP—011 Attachment 1 (at the request of the BARC SDT) by implying that maintaining reserves take priority over shedding load. 9) Creates an unnecessary administrative burden in tracking the commodity requirements of R2. 10) Provides a disincentive for a BA to assist its neighbor when a formal RSG is not present. 11) As previously noted, we believe that the definition of a BCE needs to include "the curtailment of Interchange Transaction(s) due to initiation of a TLR procedure", else the System Operator may find him/herself in a position of having to choose between activating reserves or shedding load. 12) 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. 13) 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. 14) 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. 15) 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 must be separated.
Individual
Karin Schweitzer
Texas Reliability Entity
Definition of Reportable Balancing Contingency Event: 1) Texas Reliability Entity, Inc. (Texas RE) requests clarification from the SDT as to the meaning and significance of the word "Reportable" in "Reportable Balancing Contingency Event." As the standard is currently written there is no longer a reporting obligation for balancing contingency events. BAL-002-2 has removed the language that compelled the Responsible Entity to submit the data. The following is the reporting language that has been removed: "Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of

the month following the end of the quarter." Does the SDT consider Measure 1 as the reporting mechanism? Measures are not mandatory nor enforceable components of a Reliability Standard. If the data should be submitted in any other manner than as requested (as evidence for a CMEP activity) by the Compliance Enforcement Authority (CEA) then it will need to be part of a requirement. Texas RE requests clarification from the SDT on the intent. Are Responsible Entities only required to complete the CR Form 1 after a “reportable” event and file it away until the CEA requests it? That appears to be administrative in nature with no reliability benefit. 2) For a single BA interconnection like ERCOT, having the 800 MW value specifically listed in the standard creates inconsistencies over the course of the year. ERCOT loads vary between approximately 25,000 MW and 70,000 MW at different times of the year. For example, a 500 MW unit trip at a load of 30,000 MW may create a frequency excursion below 59.85 Hz, where at a 50,000 MW load it may take a 900 MW unit trip to reach 59.85 Hz. With the current definition, only the 900 MW trip would be a reportable event even though the percentage ACE change and frequency impact are the same. Texas RE suggests that 600 MW is the correct threshold to set as it would call for a greater set of events to be analyzed. A 600 MW threshold more closely aligns to the median of data for the ERCOT region as shown in the chart on page 16 of the BAL-002-2 Background Document. The other regions appear to align close to the median so the ERCOT region number of 800 MW seems to be inconsistent. Requirement R1: The language between the bulleted items in R1, the exceptions in R1.3, and R2 is duplicative and confusing. Texas RE suggests removing the exceptions from the Requirement R1 bullets and only listing them in R1.3 and R2. In addition, the standard could benefit from an Application Guideline section that shows the calculations for different single and multi-generation loss scenarios, possibly in a graphical form. This type of technical information would create consistency across the regions on how R1 is to be interpreted. Requirement R2: Requirement R2 could also benefit from the addition of Application Guideline information showing the calculations for the first two bulleted contingency reserve recovery scenarios. This type of technical information would create consistency across the regions on how R1 is to be interpreted.
Group
Seattle City Light
Paul Haase
Seattle City Light
Seattle City Light appreciates the changes made by the Standard Drafting Team in response to previous comments. The present draft is improved, but Seattle is unable to support the ballot because of remaining concerns, primarily about the definition and use of Most Severe Single Contingency. Specifically, Seattle considers that the definition of Most Severe Single Contingency (MSSC) needs to be changed so that it is not predicated on an event happening to be able to define MSSC. We suggest the following wording to address this problem: "Most Severe Single Contingency (MSSC): The greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG to meet firm system load and export obligation that would occur for any single contingency or credible multiple contingency (excluding export obligation for which Contingency Reserve obligations are designated by E-Tag as being met by the sink Balancing Authority). MSSC will be measured and reported in one minute intervals." In addition, Seattle recommends that Requirement R2 be changed to address the double jeopardy of trying to estimate the average “Clock hour…” If the MSSC definition is changed as above, it makes R2 easier to implement and comply with. We suggest the following new wording for R2: "R2. The Responsible Entity shall maintain Contingency Reserve, greater than or equal to its Most Severe Single Contingency except during periods when the Responsible Entity is in: ..." (rest of text remains as proposed)
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
Seminole proposes rewording Part A of the definition of a Balancing Contingency Event to read “Any sudden loss of generation that causes an unexpected change to the responsible entity’s ACE.” There is no need to list all causes of a “sudden loss of generation,” as there are only those related directly to a Unit itself (trip or run back) or loss of a transmission Facility. Additionally, the term Interconnection Facility is not in the Reliability Standards Glossary of Terms, yet it is capitalized. Is it the SDT intent to make the term interconnection facility a new NERC defined term? If so, please

provide the proposed definition of the term. In the definition of MSSC, Seminole proposes the following grammatical changes: • Add a comma after “(RSG)” • Change “member of a RSG” to “member of the RSG” and add a comma after RSG • Add a comma after “at the time of the event” • Change the use of “obligation” to “obligations” R2. Comments: • In the first bullet, what is a “restoration period?” It is not a NERC defined term. The second sentence of the first bullet states it is a “required restoration,” and thus it should be its own requirement in the standard. Otherwise, it should be removed from the first bullet. • Also in the first bullet, it is unclear what type of Contingency would result in deployment of an entity’s Contingency Reserve and not qualify as a Balancing Contingency Event. Can the SDT provide examples?
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. 3. VSL Requirement R1 - There is no VSL associated with an entity failing to document Reportable Balancing Contingency Events using CR Form 1 per Requirement R1, Part 1.1. ReliabilityFirst recommends the following for an additional Moderate VSL: “The Responsible Entity failed to document Reportable Balancing Contingency Events using CR Form 1 per Requirement R1, Part 1.1”
Individual
Leonard Kula
Independent Electricity System Operator
1. In the last posting, we expressed a concern over disagree with the proposed approach to define new terms that are used solely for this standard, and the term “sudden loss”, as follows: a. We disagree with defining new terms and move them to the NERC Glossary when the standard is approved. Many of these terms are used exclusively in this standard only, and as such, should be kept within the standard and not be moved to the NERC Glossary. Moving these terms to the NERC Glossary creates unnecessary maintenance burden, and may create a conflict with similar terms used in other NERC documents. The SDT’s response indicates that the defined term is the first step toward addressing the FERC directives. While this may be a preferred approach, not all defined terms need to be incorporated in to the NERC Glossary. We once again urge the SDT to consider keeping the new terms within the standard only and not move them to the NERC Glossary. b. 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 we say 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. We find the revised R2 to be confusing, and can lend itself to gaming by entities that do not wish to or are unable to comply with the requirement and hence declare EEAs more frequently than necessary. In fact, the amount of OR and the timing to

restore the minimum OR level is material given the requirement to meet CPS1 and DCS (in R1). How and from where, and the amount of reserve a BA needs to have, are driven by meeting the performance targets specified in R1. A BA that fails to maintain the required Contingency Reserve will fail the DCS requirement. Hence, there is no need to create yet another requirement for double jeopardy. We therefore suggest that R2 be removed. Also, R2 with its current wording suggests that there are Contingencies other than BCE that require the activation of Contingency Reserve which we don't agree with as it implies that Bas can no longer activate OR for things other than Contingencies that affect ACE. If R2 is to stay, we suggest changing the word "Contingencies" to have the clause as "events that are not Balancing Contingency Events"
Group
Tennessee Valley Authority
Dennis Chastain
Tennessee Valley Authority
TVA supports the comments being filed by the SERC OC Review Group.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
LG&E and KU Energy, LLC
The PPL NERC Registered Affiliates support the comments filed by the SERC OC Review Group.
Group
ACES Standards Collaborators
Brian Van Gheem
ACES
(1) We appreciate the SDT with their efforts to address a "continent-wide contingency reserve policy" as stated in FERC Order 693 for NERC standard BAL-002 and issues raised by stakeholders and compliance teams related to other applicable Resource and Demand Balancing Standards. We also appreciate the SDT's attempt to resolve the confusion in the previous draft of this standard with additional Balancing Contingency Events that occur during the Contingency Event Recovery Period of one Balancing Contingency Event. However, we feel that the SDT needs to revise this standard even further. (2) The definition for Balancing Contingency Event is incomplete in Subsection B. The current definition states "Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection," but does not consider import changes due to the initiation of a congestion management or Transmission Loading Relief procedure. We also feel the definition of Balancing Contingency Event focuses solely on the entity experiencing the event and does not accommodate adjacent entities or other members of the entity's Reserve Sharing Group that would be providing emergency assistance. We also believe the SDT should clarify the term Contingency Event Recovery Period by including a reference for when a Responsible Entity uses its Contingency Reserve for Contingencies that are not Balancing Contingency Events. (3) The SDT should reword Part 1.2 of Requirement R1 to account for when a Responsible Entity anticipates an Energy Emergency Alert, not just when the Responsible Entity is experiencing an Energy Emergency Alert. We also believe the SDT should account for the event when a Reliability Coordinator directs the Responsible Entity to deploy a portion of its Contingency Reserves, per IRO-005-3.1a R5. (4) The reference to 105 minutes in Part 1.3 of Requirement R1 appears to be an arbitrary number. We realize that this number is the sum of the Contingency Event Recovery Period and the Contingency Reserve Restoration Period. However, we believe the SDT should include these definitions instead for clarity. (5) We believe the references to "and/or" used to separate the bullets of Requirement R2 will cause confusion and should be removed accordingly. If the drafting team intends for both actions to be complete, then "and" would be appropriate. If one or the other action, or both are intended, the word "or" should be used. This is consistent with other NERC standards and the NERC Rules of Procedure. Regardless, the language needs to be clarified. (6) The reference to 90 minutes in the first bullet of Requirement R2 appears to be an arbitrary number. We realize that this number is the Contingency Reserve Restoration Period and the SDT may have avoided the use of this term since the bullet pertains to deploying Contingency Reserves for Contingencies that are not Balancing Contingency Events. However, we feel that by revising the definition of Contingency Event Recovery Period, as mentioned earlier, the SDT can use the

Contingency Reserve Restoration Period reference in this bullet. (7) We also have concerns that the focus of this standard appears to have shifted to the tracking of Contingency Reserves, and not how an entity uses its Contingency Reserves during an event and how quickly the entity restores these reserves. We believe the former is leading this standard down the path of an administrative burden, while the latter leads to a more performance-based and risk-based approach. (8) Thank you for the opportunity to comment.
Group
IRC Standards Review Committee
Terry Bilke
MISO
1. 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. • 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. • 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. • 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. 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.] 3. 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 concern 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] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events [or in response to a Reliability Directive.] This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • 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 concern 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 concern 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. 14) Finally, the ISOs do not see a need to change from the current approach of using 80% of the largest unit within the RSG or BA or a smaller amount as chosen by the responsible entity.
Individual
Dan Roethemeyer
Dynegy
1. Dynegy's Electric Energy Inc. (EEI) entity is concerned that “Coordinated adjustments to Interchange Schedules” has been removed from allowed list of Contingency Reserve in the proposed

standard. EEI does not have load within its balancing area and relies on adjusting interchange schedules in order to meet its DCS obligation. It is not clear in the draft standard that adjustments to interchange schedules will be allowed in order to meet this obligation. EEI suggests continuing to allow “Coordinated adjustments to Interchange Schedules” as an option to meet DCS obligations in the standard.
Individual
Marie Knox
MISO
We agree with the comments submitted by the IRC’s Standards Review Committee. Additionally, we respectfully offer the following comments. One key concern is the inequitable definition of reportable events. The Eastern Interconnection is asked to report on units that are a fraction of the size of the other Interconnections. Here is the comparison. 14% East 25% West 114% ERCOT 108% HQ The East will be reporting performance for proportionally many more events than the other Interconnections, perhaps nearly 10 times as many. The threshold in the East should be 1000 MW or 80% of the largest unit within the BA or RSG, whichever is lesser. While well-intentioned, over-enforcement of the current BAL-002 standard has led to operators shedding load for no reliability reason just to achieve a zero ACE. The IROL standards are the backstop on reliability on whether ACE is causing a problem. The changes proposed in this standard will now have operators shedding load for cases where its reserves drop below a particular number. There is no doubt this tendency to over-enforce BAL-002 will continue. Each BA needs a different amount and type of reserve based on many factors. The true demonstration of reserve adequacy is CPS1, BAAL, DCS and IROL performance. It’s unfortunate that NERC is moving away from a performance based approach to standards toward a zero-defect commodity obligation. The current DCS is well understood and performance has been stellar. We would be happy to provide data to show this is the case. The proposed standard makes many changes to existing process without a demonstrated reliability need. Additionally, many of the changes do not appear to be within the scope of the SAR nor an Order No. 693 directive. This sets an unfortunate precedent. We believe the present standard should be kept mostly intact. We agree with adding clarity that the objective of the standard is to respond to events up to the Most Severe Single Contingency and that the BA should implement emergency actions if necessary to respond to events > MSSC. This does not mean shedding load as long as the BA is not causing an exceedance of an IROL. One particular challenge is the lack of common definitions for reserves. The team is proposing a commodity requirement without a definition of how to quantify the hourly number. We believe that reliability would be better served if the team followed the Order No. 693 directive to create uniform definitions in a policy document. Once these terms are defined and commented on by the Industry in the document, NERC should add the types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data”, with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. We believe there would be significant reliability value in giving RCs continent-wide visibility of the current state of Contingency Reserves (something callable in 10 minutes, fully deployed in 15 minutes and sustainable for at least 90 minutes) and Replacement Reserves (e.g. something callable in 90 minutes and sustainable for say 4 hours). This would directly contribute to reliability by providing objective information to BAs and RCs in managing Energy Emergency Alerts.
Group
Duke Energy
Michael Lowman
Duke Energy
(1) 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. (2) Duke Energy suggests the following revision to R2 bullet 3: “• 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 R2 during those instances where Contingency Reserves are utilized to serve load. (3) Duke Energy suggests the following revision to item A.a.ii. of the Balancing Contingency Event definition: “ii. Loss of generator Facility resulting in isolation of the generator from the Bulk Electric

System or from the responsible entity’s electric system, or…” We believe the use the word “Interconnection” could be viewed as redundant based on it being implied within the NERC definition of “Facility”. (4) Duke Energy seeks 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.
Individual
Spencer Tacke
Modesto Irrigation District
I am voting NO because I cannot support a change from 15 minutes to 105 minutes in Section R1 1.3. I could , however, support a change from 15 minutes to 30 minutes. Thank you.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
We believe that this draft certainly is an improvement from the last draft and from the actual standard. We suggest the SDT to take into account additional minor adjustments to improve the actual draft. We propose that the standard should follow the new NERC standard format by placing measures with associated requirements. The proposed definition for "Balancing Contingency Event", the term "Interconnection Facility" should not be capitalized as it is not a defined term in the NERC Glossary. Only the term "Facility" should be capitalized. "Interconnection" is a defined term but refers to one of the major electric system (Eastern, ERCOT, etc.) when capitalized. In this case, the term "interconnection Facility" seems to refer to a facility that is used to interconnect generation to the system. In the proposed definition for "Most Severe Single Contingency", the term "sink" should be capitalized as "Sink Balancing Authority" is a defined term in the NERC Glossary. Also, some single contingencies may lead to a generation loss as well as a load loss due to bus configuration. This load could either be end-user load or DC converters. We suggest that the “Reportable Balancing Contingency Event” and “Most Severe Single Contingency” definitions explicitly take the load loss into account. We suggest adding the words “… resulting in the net loss of MW output reduced by any concurrent load loss” in both definitions. We noticed that the background document discusses the issue stated above in the MSSC section but may not be exact in all cases. For example, a BA has three 600 MW units in a substation and a 200 MW transformer that serves load. Due to unavailable equipment in the substation, there is a bus fault that can lead to the loss of two units (1200 MW) and the transformer (200 MW). In this case, we believe that the entity’s MSSC should be 1000 MW. This following sentence is not true in all cases: “Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, it is impossible for this event to be the entity’s MSSC » . We suggest removing it from standard. R1: We suggest that the part that addresses Balancing Contingency Event (BCE) occurrences during the Contingency Event Recovery Period be not duplicated. Moreover, we ask further explanation about the use of the expression "beginning at the time of". Also, we believe that part unnecessary. The reduction cannot be applied before a BCE actually happens and the reduction is applied to the required recovery value that must be reached by the end of the recovery period. Thus, the time of the application of the reduction is not relevant. As long as the event fully occurs within the recovery period the adjustment can be made. The expression "beginning at the time of" is also not consistent with the last sentence of the background document: "Note that the adjustments to the Reportable ACE value required for recovery are made only after the subsequent Balancing Contingency Event fully occurs." Whereas the requirement states "…beginning at the time of each individual Balancing Contingency Event". To address those issues to be more clear and concise, we suggest rewording the two bullets as follows: "Zero, if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero Or Its Pre-Reporting Contingency Event ACE Value, if that value was negative. In both cases, the required recovery value for the Reporting ACE shall be reduced by the magnitude of each subsequent Balancing Contingency Event that fully occurs during the Contingency Event Recovery Period." Section 1.2 should be included in 1.3 as it is also a condition under which R1 does not apply (1.3 would become 1.2). Also in 1.3, the first part addressing BCE > MSSC is redundant since R1 applies to Reportable BCE which is defined as a BCE <= MSSC. We suggest removing the first part of 1.3 (i) and only keep the second part (ii). We propose: "1.2 Requirement R1 (in its entirety) does not apply: • when the Responsible Entity is experiencing an

Energy Emergency Alert Level under which Contingency Reserves have been activated, or • after multiple 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." The graphs in Attachment 1 of the background document should exclude load events in the statistics. These events are not relevant for the BAL-002 standard. Additionally, it makes it difficult to understand how the MW threshold for the Interconnections established from these graphs. The SDT should explain the data shown in the graphs and how it relates to the Interconnection minimums. Additionally, "hydroquebec" graph should be renamed "Quebec" Interconnection. In Attachment 2 of the background document there seem to be a mistake in the example. The second Balancing Contingency Event (200MW at 12:15) that occurs during the recovery period is cumulative to the first one resulting in a required ACE recovery value of negative 600 MW. However, the next sentence states that the responsible entity would return its Reporting ACE to negative 200 MW by 12:20 which would be a more severe requirement in response to a subsequent BCE during a recovery period. It must be corrected in the background document.
Individual
Catherine Wesley
PJM Interconnection
1. 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. • 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. • 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. • 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. 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.] 3. 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 concern 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] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events [or in response to a Reliability Directive.] This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • 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 concernfor 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 concernfor 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.
Individual

Cheryl Moseley
Electric Reliability Counccil of Texas, Inc.
ERCOT generally supports the comments submitted by the ISO/RTO Council's Standards Review Committee (IRC SRC) and provides the following additional comments: 1. ERCOT respectfully submits the following comments to remove ambiguity and streamline the definitions proposed to support this draft of the BAL-002-2 standard: a. The use of the term sudden is ambiguous and could create confusion. The following revisions are proposed: Balancing Contingency Event: 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. A. Unexpected loss of generation: a. Due to i. Unit tripping ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System iii. Unexpected, unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Unexpected loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and load within the Balancing Authority Area. C. Unexpected restoration of a load utilized as a supply resource to balance load and supply in the Balancing Authority Area that causes an unexpected change to the responsible entity's ACE. b. The definition of Most Severe Single Contingency should be streamlined to ensure that it is clear and unambiguous. The use of phrases such as "at the time of the event" could create confusion and should be eliminated from the definition. The following revisions are proposed: Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the responsible entity to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority). c. The definition of Reportable Balancing Contingency Event should be streamlined to ensure that it is clear and unambiguous. The use of phrases such as "at the time of the event" could create confusion and should be eliminated from the definition. The following revisions are proposed: Reportable Balancing Contingency Event: Any Balancing Contingency Event causing a loss of MW output less than or equal to 80% of the Most Severe Single Contingency or the amount listed below for the applicable Interconnection and occurring within a one-minute interval of the initial decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the Responsible Entity upon written notification to the Regional Entity. • Eastern Interconnection - 900 MW • The Western Interconnection – 500 MW • ERCOT – 1000 MW • Quebec – 500 MW d. The definition of Contingency Event Recovery Period should be streamlined to ensure that it is consistent with other definitions and concepts within the proposed standards and is clear and unambiguous. The following revisions are proposed: Contingency Event Recovery Period: A period beginning at the conclusion of a Reportable Balancing Contingency Event and extends for fifteen minutes thereafter. e. The definition of Contingency Reserve Restoration Period should be streamlined to ensure that it is clear and unambiguous. The following revisions are proposed: Contingency Reserve Restoration Period: A period of 90 minutes following the end of the Contingency Event Recovery Period. f. The definition of Contingency Reserve should be streamlined to ensure that it is clear and unambiguous. The following revisions are proposed: Contingency Reserve: Capacity that may be deployed by the Responsible Entity to balance load and supply within its Balancing Authority Area. The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation. 2. ERCOT has the following questions and concerns with the language in the Applicability subsections for 4.1. a. ERCOT respectfully submits that the Applicability Section is not the appropriate section within a standard to establish clarifications or compliance exceptions. This could create confusion as to when the standard is applicable to particular entities. ERCOT would prefer that all references to possible compliance exceptions are additional criteria that are addressed in Requirements and should be removed from the Applicability Section. To ensure that these additional criteria are retained within the standard, the requirements themselves should be reviewed and BA versus RSG applicability should be addressed within 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. In the alternative, to ensure clarity, the following revisions are proposed: 4. Applicability: Applicability is determined on an individual Reportable Balancing Contingency Event basis. 4.1. Responsible Entity 4.1.1 Balancing Authority that is not an Energy Emergency Alert Level under which Contingency Reserves have been activated. 4.1.2 Reserve Sharing Group that is (1) active within a particular Balancing Authority Area under the applicable agreement or governing rules for the Reserve Sharing Group and (2) not an

Energy Emergency Alert Level under which Contingency Reserves have been activated. 3. ERCOT respectfully submits that the Requirement R1 is unnecessarily complex and could be streamlined to present more definitive requirements and criteria. To ensure clarity, the following revisions are proposed: R1. The responsible entity experiencing a Reportable Balancing Contingency Event shall return to its pre-Reporting Contingency Event Reporting ACE within the Contingency Event Recovery Period. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations] • If the responsible entity's Pre-Reporting Contingency Event Reporting ACE Value was positive or equal to zero, recovery shall be demonstrated by returning its Reporting ACE to zero. • If the responsible entity's Pre-Reporting Contingency Event Reporting ACE Value was negative, recovery shall be demonstrated by returning its Reporting ACE to the value utilized for Reporting ACE immediately preceding the start of the Reportable Contingency Event. o When subsequent Balancing Contingency Events occur during the Contingency Event Recovery Period, the Reporting ACE value to be recovered shall be reduced at the start of and by the magnitude of each subsequent Balancing Contingency Event that occurs during the Contingency Event Recovery Period. Corresponding revisions are suggested to the VSLs and Measures as necessary to ensure consistency. 4. Requirement R1.1 is administrative in nature and should be removed from the Standard and included in the ROP or a guidance document. As an alternative to removing the requirement, ERCOT recommends the following change to the proposed language of R1.1 to provide an alternative to using CR Form 1. R1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 [or an acceptable alternative.] Corresponding revisions are suggested to the VSLs and Measures as necessary to ensure consistency. 5. ERCOT suggested above that compliance exceptions be more appropriately documented in the requirements. Further, the proposed language creates a potential adverse reliability consequence and operational concern for the System Operator because a Balancing Authority may declare an EEA3 (under the revised language of yet to be approved EOP-011) to indicate that it is unable to meet reserve requirements, but deployment of reserves may not yet be necessary. However, to receive an R1 compliance exemption, the BA would need to deploy some of those reserves - even if there is no immediate need to do so. This requirement would result in the impacted BA being even less able to meet its reserve requirements. Further, where subsequent reserve deployments occur to meet increased load, it is unclear as to whether this would constitute a deployment of contingency reserves under R1.2. If so, what evidence does the BA provide to demonstrate compliance? To resolve these issues as well as those discussed under Requirement R1.3, ERCOT recommends the following change to the proposed language of R1.2. R1.2. A Responsible Entity is not subject to compliance with Requirement R1 when: (i) It is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated. (ii) It has declared that it may be unable to meet reserve requirements due to system conditions (iii) It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency. (iv) The combined magnitude of multiple Balancing Contingency Events occurring within a 15 minute period exceeds the Responsible Entity's Most Severe Single Contingency. Corresponding revisions are suggested to the VSLs, Measures, and Associated Compliance Information as necessary to ensure consistency. 6. ERCOT suggests the deletion of Requirement R1.3 and the consolidation of all exceptions from compliance into one Requirement for ease of review and comprehension. Corresponding revisions are suggested to the VSLs and Measures as necessary to ensure consistency. 7. ERCOT respectfully submits 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. Accordingly, the SDT recommends the deletion of Requirement R2. Additionally, ERCOT reiterates its operational and reliability concerns set forth in Comment 6 above and notes that Requirement R2 should acknowledge the potential impacts of responding to a Reliability Directive. Specifically, 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. Accordingly, as an alternative to deletion of Requirement R2, ERCOT suggests the following changes to the proposed language of Requirement R2 to reduce ambiguity and the potential for unintended adverse reliability consequences and satisfy the aforementioned directive: R2. The Responsible Entity shall maintain Contingency Reserves greater than or equal to its Most Severe Single Contingency. Such reserves shall be measured using the average Contingency Reserve amount over each clock hour except when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • For the restoration

period following Contingency Reserve deployment in response to a Contingencies that are not Balancing Contingency Events or a Reliability Directive, which restoration period shall not exceed 90 minutes and begins when the Responsible Entity's Contingency Reserve falls below its MSSC; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • 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.] Corresponding revisions are suggested to the VSLs and Measures as necessary to ensure consistency. Additional Comments: 1. ERCOT respectfully notes that a reliability or performance-related need, such as negative historical trends for DCS recovery or compliance, has not been noted and, therefore, the proposed changes may not be necessary to ensure the reliability of the Bulk Electric System. ERCOT supports the clarification and improvement of Reliability Standards generally. In this circumstance, significant negative consequences of the proposed standard have been identified. These include, but are not limited to: a. The transformation of Contingency Reserve requirements from a reliability standard to a commodity obligation. b. Increased customer costs despite the absence of a demonstrated reliability need as BAs will be incentivized to purchase contingency reserves beyond that needed to recover from the loss of MSSC. c. Operational modifications and concerns such as: i. Increased frequency variation as BAs will be incentivized to change generation dispatch at the top of each hour to meet the R2 commodity obligation. ii. Increased SOL & IROL exceedance durations as BAs will be reluctant to deploy reserves to mitigate impacts. iii. Increased BAAL excursion minutes as BAs are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. d. Provision of a disincentive for a BA to assist its neighbor when a formal RSG Agreement is not in effect. e. Creation of 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: i. R2 requires dated documentation that demonstrates that hourly Contingency Reserves that were at least equal to the MSSC. In a three year audit period that is 26,280 one hour intervals. 1. ERCOT respectfully notes the following potential inconsistencies and omissions in the BAL-002 Standard and associated documentation: a. The Severe VSL omits the "from a Reportable Balancing Contingency Event" language that is included in the Lower, Moderate, & High VSLs. b. 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. c. 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". However, Order 693 (at P355) directs the ERO to "define a significant deviation and a reportable event". This should be corrected. d. 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 and should be corrected. e. The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled "Frequency Events Loss MW Statistics". i. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. ii. 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.
Group
SERC OC Review Group
Steve Corbin
SERC RRO
1. 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. • 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. • 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. • 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.] 3. 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] • 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 • response to a Reliability Directive; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • 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.
Individual
Sonya Green-Sumpter
South Carolina Electric & Gas
NA
Group
Associated Electric Cooperative, Inc. - JRO00088
Phil Hart
Associated Electric Cooperative, Inc. - NCR01177
AECI agrees with SERC comments 2, 3, and 4. The SDT has used the term "sudden loss" and "sudden decline" in the definitions for Balancing Contingency Event and Reportable Balancing Contingency Event. Would the SDT provide some additional guidance on what specially would be considered "sudden"? Should this be determined from a percentage of the unit lost over a time period? Would the SDT be able to provide an example of what is considered sudden and what is not (in addition to including language in the standard that aligns with this example)? AECI agrees with SERC that the use of "active status" within 4.1.1.1 is ambiguous and AECI suggests the SDT include more direction on what active status entails. However, inclusion of this concept within the requirements (as opposed to the applicability) may create more confusion than simply including more direction on what active status actually is. Serious consideration should made for whatever language to avoid the unintentional consequence of a BA in an RSG being required to cover their full

MSSC reserves when not in “active status” of the RSG. To this end, it may be advantageous to apply the exception to the RSG, and not the BA. Proposed 4.1.1.1: A Balancing Authority is the Responsible Entity when contractual membership to a Reserve Sharing Group does not exist. Proposed 4.1.1.2: A Reserve Sharing Group is the Responsible Entity for all Balancing Authority members under contract of that Reserve Sharing Group. AECI suggests the Contingency Event Recovery Period should be 30 minutes to align with other standards (BAAL).
Individual
Jo-Anne Ross
Manitoba Hydro
1) R 1.2 states: 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. R 1.3 states: 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 for which the combined magnitude exceeds the Responsible Entity’s Most Severe Single Contingency for those events that occur within a 105 minute period. R 1.2 could be added as a bullet point in R 1.3 unless there is something that distinguishes 1.2 from 1.3. If so, this should be made clear. 2) M2 states: "If any portion of the Clock Hour is excluded by rule (restoration period following a Contingency which is not a Balancing Contingency Event, an Energy Emergency Alert Level user which Contingency Reserves have been activated, Contingency Reserve Recovery Period overlap or Contingency Reserve Restoration Period overlap) then that Clock Hour is excluded from evaluation." The terminology “excluded by rule” is currently unclear and could be clarified by referring to time periods that are excluded in R2. 3) D 1.1 states: As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. This does not take Canadian legislation into account as the term “Compliance Enforcement Authority” can have different meanings in jurisdictions outside of the United States. An additional sentence could be added stating that “ In jurisdictions outside the United States the term “Compliance Enforcement Authority” may designate different entities and / or prescribe different roles.”
Group
Southern Company: Southern Comapny Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Marcus Pelt
Southern Company Operations Compliance
R1.2 Southern suggest that both the EOP-11 and BAL-002-2 SDTs should work together since the proposed language in R1.2 of BAL-002-2 may contradict the revised language of proposed.EOP-011, Attachment 1, regarding maintaining contingency reserves during an EEA condition.
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
BAL-002-2 Comments: We would like to thank the drafting for adding the clarification in the Balancing Contingency Event definition that establishes the sudden loss/restoration as that change in generation, import or load that satisfies the reporting criterion within a one-minute sliding window. This is very helpful. However, we would appreciate seeing the explanation contained in the Consideration of Comment in an Application Guideline, Associated Document, etc. section included at the end of the standard. Please hyphenate ’16-second interval’ in the definition of Pre-Reporting Contingency Event ACE Value. Please hyphenate Demand-Side Management in the definition of Contingency Reserve to make it consistent with the term in the Glossary. Responsible Entity does not appear in the NERC Glossary nor is it capitalized in the Functional Model. In fact, the Functional Model encourages the use of the term as ‘responsible entity’. Shouldn’t this standard be changed to reflect that recommended usage? Thank you also for further clarifying that the responsible entity is not subject to compliance with this standard during periods when the responsible entity is in an Energy Emergency Alert Level in which Contingency Reserves have been activated. Hopefully, this

will be understood by the Emergency Operations drafting team. Again, thank you for the clarifying changes to Requirement R1. It is much easier to read than the previous version. In Requirement R1, Part 1.3(ii) hyphenate '105-minute period'. In Requirement R2, the responsible entity is required to maintain Contingency Reserve, averaged over each Clock Hour. Can the drafting team provide any insight into a recommended scan rate for this averaging? Also, a similar average Clock Hour Most Severe Single Contingency (MSSC) is established as the bar for compliance. How often does the drafting team expect MSSC to change? Is this averaging done on a similar basis as Contingency Reserve? In the past, MSSC has been set based on system norms for a given period – for example a year in the existing standard and then modified daily on an availability basis. Does the drafting team really mean an average MSSC for the hour or is it the Real-time value of MSSC during the hour? In the 3rd line of M2, change 'documenting' to 'documented'. Background Document Comments: In the 5th line of the 1st paragraph of the Introduction, change 'are' to 'were'. This paragraph refers to historical events and even though the requirement is still active, past tense would be the preferred usage. Please hyphenate Demand-Side Management in the 4th line of the 1st paragraph under Contingency Reserve to make it consistent with the term in the Glossary. Responsible Entity does not appear in the NERC Glossary nor is it capitalized in the Functional Model. In fact, the Functional Model encourages the use of the term as 'responsible entity'. Shouldn't this document be changed to reflect that usage? The Emergency Operations drafting team has proposed to eliminate the term Energy Deficient Entity in the new EOP-011-1 standard. Shouldn't that terminology be phased out in the Background Document in the 4th line of the 2nd paragraph under Contingency Reserve? In the 4th paragraph under Background and Rationale for Requirement R1, capitalize Parts as in 'R1 Parts 1.2 and 1.3'. Also, delete the 'R' in front of 1.3. In the 3rd line of the same paragraph, use lower case 'standards' or use 'Reliability Standards'. In the 1st line of the 5th paragraph under Background and Rationale for Requirement R1, insert a 'the' between 'by' and 'Consortium'. In the 9th line of the 4th paragraph under Background and Rationale for Requirement R2, capitalize 'Real-time'. The language of the 2nd and 3rd subsequent events in the Attachment 2 example is very confusing. We recommend rewording the 1st line at the top of Page 20 (the 2nd subsequent event in the example) to read '…required ACE recovery being reduced by 400 MW to -400 MW.' Similarly, in the 3rd subsequent event in the 3rd line of the paragraph below the bullets on Page 20, reword the line to read '…required ACE recovery being reduced by another 200 MW to -600 MW.' We recommend that the RSAW be revised to reflect the modified language we have proposed for the standard.
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 the second bullet, 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). BPA has included an example using the Example in Attachment 2 of the NERC BAL-002 Background Document to demonstrate and add clarity to the statement above. The example includes a diagram that will emailed separately to Darrel Richardson (NERC Standards Developer) and Jerry Rust, SDT member.
Individual
Robert Blohm
Keen Resources Ltd.
Consideration of the changes I repeatedly proposed here http://www.robertblohm.com/BAL-002-2 was repeatedly put off by the drafting team. Please consider them now. I proposed the changes here http://www.robertblohm.com/BAL-002-2-Background-Document in the previous comment round and, together with my comments on them in that round, they were never addressed by the drafting team. Please consider them this time.