Individual or group. (32 Responses)
Name (20 Responses)
Organization (20 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (7 Responses)
Comments (32 Responses)
Question 1 (23 Responses)
Question 1 Comments (25 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Firstly, we would like to thank the SDT for their efforts and consideration of these comments. We continue to disagree with defining new terms that are unique to this standard and then including them in 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 this standard and not moved to the NERC Glossary. Moving these terms to the NERC Glossary creates an unnecessary maintenance burden, and may create a conflict with similar terms used in other NERC documents. We agree with the Drafting Team's goal to better define when the requirements apply. The approach taken makes it difficult to follow the true meaning of the requirements. We get differing opinions among our peers on what the standard is saying. There are different approaches used in the standards to say when a requirement applies and when it doesn't ("exemptions", "exclusions", or "does not apply"). We suggest an alternative approach that would simplify the requirements. We recommend adding a Part under each requirement detailing exclusions. Exclusions: • R1 and R2 do not apply during EEA 2 or EEA 3. • R1 does not apply for multiple non-simultaneous events [Rationale: These events are adequately addressed by IROL, BAAL and EEA requirements] (footnote 1 below) • R1 does not apply for single or simultaneous events where the capacity loss is > MSSC. This will allow the Drafting Team to use simpler wording for the requirements. Footnote 1--The IROL standards still require operators to take whatever action is necessary to prevent cascading with the next contingency, to include shedding load or redispatch. The new BAL-001 standard will require the Balancing Authority to take action within 30 minutes to get frequency back within acceptable bounds. The Energy Emergency Alert process still exists to address any reserve shortfall. Comments on R1 Events > MSSC. As noted earlier, events where the capacity (not MW) loss > MSSC should not be evaluated under this standard. Even if the MW loss was within the reporting threshold, the BA would have lost the reserves it needed to assist the recovery. We agree that events > MSSC can be reported on a different sheet on the reporting form, but there should not be an associated measure. The report should capture the time, unit, power, and capacity loss. Multiple lines on the report would be needed for each event series. When multiple contingencies occur, we want the operator to assess their actions based on impact on the transmission system rather than achieving a zero ACE. As noted earlier, there are protective backstops in place (IROL, BAAL, EEA). Change from Quarterly Metric. DCS performance has always been calculated and reported on a quarterly basis. This is similar to CPS1 and CPS2 whose performance is based on annual and monthly calculations. While we understand that this change was a directive in Order No. 693, the Drafting Team has the option to point out the rationale why the directive will have unintended consequences. We believe this single event metric will lead to changes in how Reserve Sharing Groups select events, only reporting those very large events rather than allowing members to call for reserves for smaller contingencies. This is a step backward from a reliability perspective. Should the Drafting Team decide to not retain the quarterly metric, we strongly recommend staying with a quarterly report form with each event listed separately to reduce the administrative overhead. Comments on R2: As proposed we believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The original Policy 1 listed multiple reasons for

carrying operating reserves (errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity). The first unintended consequence is that BAs are discouraged from deploying their contingency reserves except for DCS-reportable events. There will be a reluctance to deploy reserves if it will take the balance to less than MSSC. We may also experience repeated frequency swells at the start and end of each hour as BAs try to “bank” average reserves or make up for earlier deficiencies early in the hour. The second unintended consequence for those BAs that don’t withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more contingency reserves than their MSSC. This will increase costs to our customers without a demonstrated need. What is the driver for this requirement? It is not within the scope of the Drafting Team’s SAR, nor was it directed in Order No. 693. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. One approach is to include a commodity measure that fits within the context of the original DCS and would not discourage the operator from deploying reserves for non-reportable events. For example, consider a medium size BA that has heavier than expected loads due to rain/darkness and associated wet coal conditions at one or more of its plants: • The operator starts falling behind on the load pickup, but deploys most of its on-line reserves to keep up with load. • Because of the wet coal, there are some limitations on the units that further reduce its reserves. • The operator finds out 10 minutes after the hour that they were < MSSC on reserves. • The operator initiates action to replenish reserves, but since s/he is already well into the hour, s/he won’t be able to fully recover them for 90 minutes (same as the current standard expects). This means the operator did the right thing, but had 3 hours where reserves were < MSSC. As long as the operator had a plan and could withstand the next contingency, there is no negative impact on reliability. Finally, as we noted in the informal posting of this standard, the team has not provided a simple, clear definition on how contingency reserves are measured as prosed under R2. The definition should be something that can be implemented in an EMS. Does it include all generation headroom available in 10 minutes? In 15 minutes? Do regulating resources with headroom count as contingency reserves? Are load resources available in 15 minutes or 10 minutes counted? What about demand response resources that aren’t directly measured? Proposed Solutions: As noted earlier, we recommend including exclusions that will allow simplification of the requirements. The two requirements could then be simplified as follows: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: • Zero, if pre-contingency ACE was positive or equal to zero. • Pre-contingency ACE value, if pre-contingency ACE was negative. We offer two suggestions for R2: R2. The Responsible Entity experiencing a Reportable Event shall replenish its Contingency Reserves within 105 minutes of the onset of the Reportable Event. Alternatively, it would be consistent with the current standard to have: R2. The Responsible Entity’s hourly average Contingency Reserves shall not be < its MSSC for more than three consecutive clock hours. In addition regarding R2, the removal of the “five hours exemption” in R2 is not an enhancement since it could encourage some BAs to avoid activating their contingency reserves in some situations to avoid being non-compliant. For example, if there is an important un-forecasted increase of demand, an IROL limit violation or a voltage problem, the activation of contingency reserve could probably most of the time resolve the problem. With the new proposition it would lead to a non-compliance on R2 of BAL-002-2. Because of this the 5 hours exemption should be considered to be kept for reliability reasons. Considering the Quebec Interconnection, there are contingencies that occur where generation and load are lost at the same time. There are contingencies where 1900 MW of generation is lost and 1600 MW of DC converters at the same time, the net loss for the BA/Interconnection being 300 MW. The net loss causes a small ACE change and is under the Reportable Balancing Contingency Event threshold. In addition, the 1600 MW of DC converter loss would probably be reported by another entity as a DCS due to a loss of an import. For this reason, suggest that the Balancing Contingency Event and the Reportable Balancing Contingency Event definitions be revised to include the concept of net loss for the BA instead of only the generator MW output. As for the Reportable Balancing Contingency Event threshold, the 500 MW threshold for the Quebec Interconnection should be reconsidered. As for now, the actual threshold set at 80% of MSSC which corresponds generally around 800 MW already traps events that are significant for the Interconnection and truly measure events where contingency reserve is being deployed by operator actions. A too low threshold might capture events that are recovered with frequency response and AGC action, which are deployed quickly after the event since Quebec is in a

single BA Interconnection. The proposed threshold in the draft would augment the reporting needs without any improvement in measuring contingency reserve deployment.
Individual
Thomas Foltz
American Electric Power
Yes
AEP questions if this new version is an improvement over the current BAL-002-1. There are many more terms that are cross referenced and it will become a risk that operators will struggle to tie all the pieces together. This proposed standard, while it might be more flexible in some regards, might cause unnecessary confusion. AEP recommends changing the definition for Balancing Contingency Event to the following: “Any single event described below, or any series of such otherwise single events, with each separated from the next by less than one minute and, that causes a significant change to the responsible entity’s ACE caused by 1. Sudden loss of supply (generation or import), not including controlled shutdown of a unit. …or … 2. Restoration of a load” Reserve Sharing Group Reporting ACE: the addition of the “at the time of measurement” is now stated twice in the same sentence. We believe one of the references should be removed. R1 1.1, 1.2, and 1.3: The content provides guidance and exception information, but includes no obligatory language. As a result, these sub requirements should instead be moved into either footnotes or bullet points. R2 is very difficult to follow with all of the exceptions. Furthermore, it would be better to start with the expected obligation and have the exceptions to the rule follow in the sentence or maybe in a footnote. We do support some amount of a “grace period” during these events, however, what is the reliability basis for the 5 hour duration?
Individual
Gerald G Fattinger
Consumers Energy
Yes
a) The definition of Balancing Contingency Event is long and cumbersome. Any loss of generation or import no matter how minor is considered a Balancing Contingency Event. The true trigger for an Event should be a change in the ACE of a specified amount of percentage. The cause of the deviation (other than meter or telemetry error) is immaterial and has no real impact on actions taken. b) Having a definition of a Contingency Event and a Reportable Contingency Event is piling on. One definition is all that is required. c) Applicability to a Reliability Standard should not be dependent on an Event. This is either applicable to a BA or RSG or it is not. The fact that the measurement only happens when a Recordable Event occurs is irrelevant to the applicability. d) This standard is difficult to read through and overly complicated. e) Definitions in BAL-002-1 are clear and succinct. They should remain for this standard.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We continue to 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. 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.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC Review Group
Individual
Kayleigh Wilkerson
Lincoln Electric System
Yes
Although supportive of the drafting team's efforts to improve BAL-002, LES is concerned with the proposed definitions of Most Severe Single Contingency (MSSC) and Reportable Balancing Contingency Event. As drafted, the definition of MSSC does not clearly state whether or not the Reserve Sharing Group (RSG), or the Balancing Authority not in a RSG, can define whether or not the MSSC is operationally defined or defined in advance. Additionally, the definition of Reportable Balancing Contingency Event is confusing as proposed. Recommend the drafting team consider incorporating a formula within the definition to provide additional clarity.
Individual
Kathleen Goodman
ISO New England Inc.
We believe the term “sudden” should be defined as a “step change.” Does “imbalance between generation and load on the Interconnection” imply causing an imbalance beyond the BA or RSG boundary? Could that mean that associated transaction curtailments factor into the overall contingency size? “Begins to decline” in the definition of Contingency Event Recovery Period should be “Begins to decline unexpectedly.” “Averaged over each Clock Hour” should be averaged over three to five clock hours so as to be manageable practically from an operational perspective. Suggest modifying R2, as: “R2. Except during the Responsible Entity’s Contingency Event Recovery Period and the Responsible Entity’s Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over a rolling (3-5) Clock Hour interval at least equal to the average of the Most Severe Single minus the average Area Control Area over the same interval.” Generally speaking, the requirement to maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency may, in fact, reduce reliability. As we read it, the only two reasons that these reserves may go below MSCC are: during an EEA 2 or 3; or during the Contingency Reserve Restoration Period. Therefore, in order to maintain compliance, one might not deploy reserves for events such as a missed load forecast, opting instead to “drag” on the Interconnection. This seems counterintuitive to a reliability standard. Requirement 1.2 does not provide clarity as to the applicable EEA 2/3 trigger. Can the Contingency Event itself trigger the EEA? Assuming it cannot, alternate language may be: “1.2. Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3 at the time that the Reportable Balancing Contingency Event occurs.”
Individual
Marie Knox
MISO
Yes
We appreciate the efforts of the drafting team as well as the opportunity to comment. Our primary concern is that this project is taking a step back from performance-based standard and moving

toward a zero-defect commodity obligation. The intent of the original Policy 1 DCS was to prepare for contingencies of any type and restore balance after they occur. It was understood that multiple events and unforeseen situations arose. This is why performance was measured over many events over a quarter. What is now proposed will likely lead to several negative unintended consequences (added cost for no identified need, wider intra-hour frequency variation to as BAs change dispatch to always have a given hourly average, fewer reportable events as each event is singularly sanctionable, and a likely step increase in the calling of EEAs 2 and 3). The reality is most of the Order No. 693 items the team is attempting to address have already been more effectively covered by BAL-001-2 R2 (commonly called BAAL). Simplifying the Verbiage in the Standard While we agree with the drafting team's goal to better define when the requirements apply, the wording makes it difficult to follow the true meaning of the requirements. We get differing opinions among our peers on what the standard is saying. The current standards use several different approaches to say when a requirement applies and when it doesn't (search on "exemptions", "exclusions", or "does not apply" to find examples). We suggest the following to make the requirements simpler. First, we recommend adding an "Exclusions" section under "Applicability". Exclusions: • R1 and R2 do not apply during EEA 2 or EEA 3. • R1 does not apply for multiple non-simultaneous events [Rationale: These events are adequately addressed by IROL, BAAL and EEA requirements] • R1 does not apply for single or simultaneous events where the capacity loss is > MSSC. This will allow the drafting team to use simpler wording for the requirements. Comments on R1 Events > MSSC. As noted earlier, events where the capacity (not MW) loss > MSSC should not be evaluated under this standard. Even if the MW loss was within the reporting threshold, the BA would have lost the reserves it needed to assist the recovery. We agree that events > MSSC can be reported on a different sheet on the reporting form, but there should not be an associated measure. The report should capture the time, unit, power, and capacity loss. Multiple lines on the report would be needed for each event series. When multi-contingent events occur, we want thoughtful and measured action on the part of the operator. In most cases the first priority is to assess their actions based on impact on the transmission system rather than achieving a zero ACE. As noted earlier, there are protective backstops in place (IROL, BAAL, EEA). Change from Quarterly Metric. DCS performance has always been calculated and reported on a quarterly basis. This is similar to CPS1 and CPS2 whose performance is based on annual and monthly calculations. While we understand that this change was a directive in Order No. 693, the drafting team has the option to point out the rationale why the directive will have unintended consequences. We believe this single event metric will lead to changes in how Reserve Sharing Groups select events, only reporting those very large events rather than allowing members to call for reserves for smaller contingencies. This is a step backward from a reliability perspective. Should the drafting team reject the comment to retain the quarterly metric, we strongly recommend staying with a quarterly report form with each event listed separately to reduce the administrative overhead. Comments on R2 As proposed we believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The original Policy 1 listed multiple reasons for carrying operating reserves (errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity). The first unintended consequence is that BAs are discouraged from deploying their contingency reserves except for DCS-reportable events. There will be a reluctance to deploy reserves if it will take the balance to less than MSSC. We may also experience repeated frequency swells at the start and end of each hour as BAs try to "bank" average reserves or make up for earlier deficiencies early in the hour. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more contingency reserves than their MSSC. This will increase costs to our customers without a demonstrated need. We could offer one approach to including a commodity measure that fits within the context of the original DCS and would not discourage the operator from deploying reserves for non-reportable events. A scenario would help explain this suggestion. Consider a medium size BA that has heavier than expected loads due to rain/darkness and associated wet coal conditions at one or more of its plants: • The operator starts falling behind on the load pickup, but deploys most of its on-line reserves to keep up with load. • Because of the wet coal, there are some limitations on the units that further reduce its reserves. • The operator finds out 10 minutes after the hour that they were < MSSC on reserves. • The operator initiates action to replenish reserves, but since s/he is already well into the hour, s/he won't be able to fully recover them for 90 minutes (same as the

current standard expects). This means the operator did the right thing, but had 3 hours where reserves were < MSSC. As long as the operator had a plan and could withstand the next contingency, there is no negative impact on reliability. Finally, as we noted in the informal posting of this standard, the team has not provided a simple, clear definition on how contingency reserves are measured as prosed under R2. The definition should be something that can be implemented in an EMS. Does it include all generation headroom available in 10 minutes? In 15 minutes? Do regulating resources with headroom count as contingency reserves? Are load resources available in 15 minutes or 10 minutes counted? What about demand response resources that aren't directly measured? Proposed Solutions for the Standard As noted earlier, we recommend including an "Exclusions" subsection under "Applicability" that will allow simplification of the requirements. The two requirements can then be simplified as follows: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: • Zero, if pre-contingency ACE was positive or equal to zero. • Pre-contingency ACE value, if pre-contingency ACE was negative. We offer two suggestions for R2: R2. The Responsible Entity experiencing a Reportable Event shall replenish its Contingency Reserves within 105 minutes of the onset of the Reportable Event. Alternatively, it would be consistent with the current standard to have R2. The Responsible Entity's hourly average Contingency Reserves shall not be < its MSSC for more than three consecutive clock hours. Other Recommendations to Support Reliability We again suggest an informed approach to first provide simple definitions of the different types of reserves (in particular for this standard, contingency reserves and replacement reserves). Once these terms are defined and commented on by the Industry, NERC should add these types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation 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 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 (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.
Individual
Barbara Kedrowski
Wisconsin Electric Power Co.
Agree
MISO
Group
Duke Energy
Michael Lowman
Yes
(1) Duke Energy believes that the existing definition of a Balancing Contingency Event is redundant and imprecise. We recommend that the definition be revised as follows: Balancing Contingency Event: Any single event described in Subsections (A) or (B) 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 or import due to Unit tripping or the sudden unplanned outage of transmission Facility that causes an unexpected change to the responsible entity's ACE; B. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE. Duke Energy has previously commented that Item B of the existing Balancing Contingency Event definition should be removed because it is already covered under Item A. The modification of Item (A) to include "Sudden loss of generation or import…" makes it clear and explicit that Item (A) includes the loss of an import due to either unit trip or the sudden unplanned outage of a transmission facility. In addition, there is no need to cover the loss of Interconnection Facilities in the existing section (A)(a)(ii) because Interconnection Facilities are included in transmission Facilities and would also necessarily result in a unit trip, and both of these circumstances are covered elsewhere in the definition. The existing definition also refers to "unplanned outage of transmission Facility" in section (A)(a)(ii) versus the reference to "forced outage of transmission equipment" in section (B). Duke believes that describing transmission outages using different terms within the same definition will result in confusion and differing interpretations of the meaning of the definition. The proposed

elimination of section (B) resolves this issue as well. (2) Regarding Requirement 2, Duke Energy still maintains that this Standard should remain a results-based Standard and not burden responsible entities with the tracking of reserves maintained. The existence of a requirement such as R2 will result in inefficient utilization of resources, increased costs, inaccurate representation of resource capability, and other negative consequences with no benefit to reliability. (3) Duke Energy suggests combining and rewording sub-requirement 1.2 and 1.3 as follows: “R1.2 Requirement R1 (in its entirety) does not apply to the Responsible Entity if any of the following occurs: 1.2.1 The Responsible Entity experiencing a Reportable Balancing Contingency Event is also experiencing an Energy Emergency Alert Level 2 or Level 3. 1.2.2 The Responsible Entity experiencing a Balancing Contingency Event has an additional event causing the sum of the aggregated events to exceed its MSSC within 15 minutes of the original BCE. 1.2.3 A subsequent BCE that occurs beyond the 15 minute period but is within 105 minutes of the first Balancing Contingency Event provided that the sum of the BCEs exceeded the Responsible Entity’s Most Severe Single Contingency.” We feel that this wording describes more clearly those instances where a Responsible Entity is not required to report the event as described in Requirement 1.
Group
IRC Standards Review Committee
Terry Bilke
Yes
Background and General Comments We appreciate the efforts of the drafting team as well as the opportunity to comment. We agree with the drafting team’s goal to better define when the requirements apply. The approach taken makes it difficult to follow the true meaning of the requirements. We get differing opinions among our peers on what the standard is saying. There are different approaches used in the standards to say when a requirement applies and when it doesn’t (“exemptions”, “exclusions”, or “does not apply”). We suggest an alternative approach to make the requirements simpler. We recommend adding an “Exclusions” section under “Applicability”. Exclusions: • R1 and R2 do not apply during EEA 2 or EEA 3. • R1 does not apply for multiple non-simultaneous events [Rationale: These events are adequately addressed by IROL, BAAL and EEA requirements] • R1 does not apply for single or simultaneous events where the capacity loss is > MSSC. This will allow the drafting team to use simpler wording for the requirements. Comments on R1 Events > MSSC. As noted earlier, events where the capacity (not solely MW) loss > MSSC should not be evaluated under this standard. Even if the MW loss was within the reporting threshold, the BA would have lost the reserves it needed to assist the recovery. We agree that events > MSSC can be reported on a different sheet on the reporting form, but there should not be an associated measure. The report should capture the time, unit, power, and capacity loss. Multiple lines on the report would be needed for each event series. When multi-contingent events occur, we want thoughtful action on the part of the operator. In most cases they should assess their actions first based on impact on the transmission system rather than achieving a zero ACE. As noted earlier, there are protective backstops in place (IROL, BAAL, EEA). Change from Quarterly Metric. DCS performance has always been calculated and reported on a quarterly basis. This is similar to CPS1 and CPS2 whose performance is based on annual and monthly calculations. While we understand that this change was a directive in Order No. 693, the drafting team has the option to point out the rationale why the directive will have unintended consequences. We believe this single event metric will lead to changes in how Reserve Sharing Groups select events, only reporting those very large events rather than allowing members to call for reserves for smaller contingencies. This is a step backward from a reliability perspective. Should the drafting team reject the comment to retain the quarterly metric, we strongly recommend staying with a quarterly report form with each event listed separately to reduce the administrative overhead. Comments on R2 As proposed we believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The original Policy 1 listed multiple reasons for carrying operating reserves (errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity). The first unintended consequence is that BAs are discouraged from deploying their contingency reserves except for DCS-reportable events. There will be a reluctance to deploy reserves if it will take the balance to less than MSSC. We may also experience repeated frequency swells at the start and end of each hour as BAs try to “bank”

average reserves or make up for earlier deficiencies early in the hour. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more contingency reserves than their MSSC. This will increase costs to our customers without a demonstrated need. We struggle to understand the driver for this requirement. It is not within the scope of the drafting team's SAR, nor was it directed in Order No. 693. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. We could offer one approach to including a commodity measure that fits within the context of the original DCS and would not discourage the operator from deploying reserves for non-reportable events. A scenario would help explain this suggestion. Consider a medium size BA that has heavier than expected loads due to rain/darkness and associated wet coal conditions at one or more of its plants: • The operator starts falling behind on the load pickup, but deploys most of its on-line reserves to keep up with load. • Because of the wet coal, there are some limitations on the units that further reduce its reserves. • The operator finds out 10 minutes after the hour that they were < MSSC on reserves for the previous hour. • The operator initiates action to replenish reserves, but since s/he is already well into the hour, s/he won't be able to fully recover them for 90 minutes (same as the current standard expects). This means the operator did the right thing, but had 3 hours where reserves were < MSSC. As long as the operator had a plan and could withstand the next contingency, there is no negative impact on reliability. Finally, as we noted in the informal posting of this standard, the team has not provided a simple, clear definition on how contingency reserves are measured as prosed under R2. The definition should be something that can be implemented in an EMS. Does it include all generation headroom available in 10 minutes? In 15 minutes? Do regulating resources with headroom count as contingency reserves? Are load resources available in 15 minutes or 10 minutes counted? What about demand response resources that aren't directly measured? Proposed Solutions As noted earlier, we recommend including an "Exclusions" subsection under "Applicability" that will allow simplification of the requirements. The two requirements can then be simplified as follows: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: • Zero, if pre-contingency ACE was positive or equal to zero. • Pre-contingency ACE value, if pre-contingency ACE was negative. We offer two suggestions for R2: R2. The Responsible Entity experiencing a Reportable Event shall replenish its Contingency Reserves within 105 minutes of the onset of the Reportable Event. Alternatively, it would be consistent with the current standard to have R2. The Responsible Entity's hourly average Contingency Reserves shall not be < its MSSC for more than three consecutive clock hours.

Individual

Anthony Jablonski

ReliabilityFirst

Yes

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. Also, the SDT responses to the last comment period indicated that the CR Form 1 would be included as an attachment to the standard, but after review the form has yet to be attached. ReliabilityFirst recommends attaching it to the standards along with the following change for consideration: "All Reportable Balancing Contingency Events [shall] be documented using Attachment 1 - CR Form 1." 2. Requirement R1, Part 1.3 - For consistency with the second sentence of Requirement R1, Part 1.3, ReliabilityFirst recommends using the word "shall" in the first sentence. ReliabilityFirst recommends the following for consideration: "Requirement R1 (in its entirety) [shall] not apply…" 3. Requirement R1, Part 1.3 - ReliabilityFirst requests the rationale behind using the 105 minute timeframe referenced in the second sentence of Requirement R1, Part 1.3. ReliabilityFirst is trying to understand if there is any technical merit behind this timeframe or if it is solely based on SDT experience. 4. 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 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. 5. 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”
Group
Seattle City Light
Paul Haase
Yes
R2 cannot be implemented or audited as written. There are two flaws. The first flaw is that R2 requires entities to carry Contingency Reserves equal to its MSSC. The problem is that Contingency Reserves, as specified in the draft, are "averaged over each clock hour" whereas MSSC is defined as the MW output of the largest source AT THE TIME OF AN EVENT; i.e. the requirement demands the logical impossibility of measuring an hourly average against an instantaneous value. Absent an event, the comparison cannot be made. The second flaw is that by defining Contingency Reserves as an hourly average, entities are left chasing a target that is not defined until an hour is over. It is possible to employ a conservative reserve profile for the first half of an hour and then ramp up as necessary to meet the target, as it become better known. Employed broadly, this approach could leave the BES short of reserves during the first half of each hour, and does not improve reliability. Seattle recommends that the draft be changed to require an instantaneous value of Contingency Reserves to address both of these flaws. Seattle recognizes the effort of the Standard Drafting team to afford flexibility in meeting Contingency Reserve requirements, but finds the approach as written to be unworkable. Although we ballot in support of the present draft, to indicate that it represents an improvement over existing Standard, Seattle will vote NO for future drafts that do not address the flaws in R2 as presently written.
Group
Southern Company: Southern CompanyServices, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Marcus Pelt
Yes
Southern disagrees with removing the additional 5 hours in a given calendar quarter and the changes made to the VSLs for R2. The industry and NERC are trying to move away from the “zero defect” concept, and the changes to this draft of the standard reintroduce the “zero defect” concerns. As currently drafted, an entity could have one clock hour where the average Contingency Reserve is 99% of the MSSC and be found non-compliant under R2. Southern recommends incorporating a reasonable tolerance period into R2 so that an entity is not in violation in this example.
Individual
Howard F. Illian
Energy Mark, Inc.
No
I have no issues with this draft and support its implementation.
Individual
Oliver Burke
Entergy Services, Inc.
Yes

Entergy does not support the use of an hourly metric as it will force unnecessary, expensive, and counterproductive activities to meet a compliance requirement. NERC SDT should consider longer time increment.
Individual
Silvia Parada Mitchell
NextEra Energy
Yes
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. NextEra comments: 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 redispatch 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. C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity’s ACE. NextEra comments: 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.
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
(1) Reportable Balancing Contingency Event, D2 - to improve clarity, we suggest removing “equal to”. We realize that this will result in some MW difference. For example: Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden 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. So, if the MSSC is 1000MW and no wording is changed, the reportable range would be 800MW -1000MW. If “equal to” is removed, then the reportable range is 801MW – 999MW. (2) R1, 1.2 – this statement may not be necessary given the language in 4 about the applicability of the standard. It seems redundant. (3) R1, 1.3 – the word ‘is’ appears to be missing from before the word ‘experiencing’. Also, to be consistent, the second sentence should say ‘R1 (in its entirety) also shall…’. (4) R1, 1.3 – “an Balancing Contingency …” should be “a Balancing Contingency” (5) R2 – as in R1, 1.2, the carve out for an Energy Emergency Alert does not seem necessary given section 4. (6) M2 – Clock Hour is not consistently capitalized. There is no explanation of what EEA 2 or EEA 3 is. (7) Compliance, 1.4 – again, the carve out for Energy Emergency Alert does not seem necessary given section 4.
Individual
Robert Blohm
Keen Resources Ltd.
Yes
SUGGESTED IMPROVEMENTS TO THE STANDARD Re R1: Remove the comma before the parenthesis, in 2 places Re R1.3 To meet FERC’s objection that as written R3 impairs reliability by stopping recoveries in process from completing, append to the very end of subsection 1.3 of

Requirement R.1: “This exemption does not retroactively apply to any recovery in process. The ACE compliance threshold of any recovery in process should still be adjusted per Requirement R.1 by all events subsequent to the last event in recovery that fall within the Contingency Event Recovery Period of the recovery in process.” Re R2 R2's contingency-reserve requirement should be replaced by this frequency-adjusted simple time-relative contingency-reserve requirement metric: Monthly average of (Hourly average Reserve / Hourly average of (GenerationDeployed + Load + BiasShareOfHourlyAverageDeltaFinMW)) >= >= MSSC / Monthly average of Hourly average of (GenerationDeployed + Load + BiasShareOfHourlyAverageDeltaFinMW). The frequency adjustment gives equal weight to the RE’s system reliability obligation as to its load obligation and its generation deployment. Since bias is a negative number, the frequency adjustment relieves the reserve requirement when the RE is contributing to over-frequency and increases the reserve requirement when the RE is deemed to be contributing to under-frequency. Re R3: "experiencing an" should be "experiences a" SUGGESTED IMPROVEMENTS TO THE BACKGROUND DOCUMENT Re "Requirement 1" section: The second line should not be indented. The outer bullets should be dots, not circles, in conformity with the Standard's style. There should be no comma before "Or". Re "Compliance Calculation" section: Insert as the preamble of the section the paragraph "It is very important to note that compliance is calculated in a way equivalent to the wording of Requirement R1, but in a way opposite to the wording of R1. In particular, R1 lowers the Target ACE to exempt subsequent events from the recovery requirement because the Reportable ACE observed by operators cannot be adjusted for subsequent events. On the other hand, the compliance calculation per CR Form 1 does not adjust the Target ACE for subsequent events and instead adjusts the Reportable ACE by removing the subsequent events from the Reportable ACE. The compliance result is the same either way, but this difference needs to be noted to properly understand the following description and relate it to the wording of R1." The first bullet's text should be left-hand justified with the first line of the bullet's text. The bullet's first line should be hanging, not indented. Delete the comma after "and" in the first bullet. Insert in the following bullets the phrases that are in ALL CAPS o If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any, OCCURRING BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event. o If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any, OCCURRING BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value. Re page 8: In the second paragraph “entity(s)” should be “entity’s”. Re page 10, insert the phrase in ALL CAPS into: SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW) AND BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE. The formulas should be replaced by the standard mathematical notation listed at http://www.robertblohm.com/BackgroundDocumentMath.doc and cross-referenced to the spreadsheet which does not allow standard mathematical notation.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL; Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE,

PA, PSE, RP, TO, TOP, TP, and TSP. Applicability Section: 4.1.1 needs clarification. It is unclear what “not in active status” means. Specifically, it is unclear whether a BA may be in “active status” by simply being under an RSG agreement and governing rules. It is unclear whether a BA not choosing to call on RSG assistance for any single Balancing Contingency Event (whether Reportable or not) would be considered “not in active status.” This makes R2 unclear as to whether and when the BA is the Responsible Entity as well as what MSSC and reporting threshold would apply. PPL suggests the following language: A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only for the Reportable Balancing Contingency event(s) during which the Balancing Authority does not request assistance from the Reserve Sharing Group under the applicable agreement or governing rules for the Reserve Sharing Group. Rather than prescribe the commercial arrangements between members of a RSG, the above language respects whatever arrangements RSG members have put in place recognizing that these arrangements must enable the group and its members to remain in compliance with all applicable requirements. In R1, the revised language is still confusing. It is unclear how a Balancing Contingency Event can be both “subsequent” and “already occurred” to a Reportable Balancing Contingency Event. PPL cannot suggest a solution as we don’t understand the intent of the added language. In R2, the calculation/evaluation of the 5 hour/quarter “exception clock” did not need elimination – it needed explanation. It is unclear whether the exception clock was to be evaluated as the average, mean or median of the Contingency Reserves held for a Clock Hour. M2 specifies a Clock Hour as the time increment to be used – Clock Hour should also be stated in R2. PPL suggests that the 5-hour exception clock be based on the Clock Hour average amount of Contingency Reserves held by the Responsible Entity (BA or RSG) for the calendar quarter. The elimination of the 5-hour exception clock and added requirement to maintain an hourly average amount of Contingency Reserve is not an improvement of R2. As the proposed standard is significantly different from the historical/existing DCS, a draft RSAW should be provided so Responsible Entities can have an indication of how compliance will be evaluated.
Group
SERC OC Review Group
Sammy Roberts
Yes
We would like to thank the SDT for their hard work and perseverance in developing this standard as well as the opportunity to provide comment. A) Requirement 1: Likewise, the changes made to Requirement 1, while adding to complexity, are positive changes. Additional clarity may be achieved by restructuring the requirement in tabular form with the simplest scenario listed first. B)Requirement 2: While we agree with the intent of Requirement 2, we continue to believe that the proposed language will have unintended consequences from the intended objective and could inject an unnecessary element into the Balancing Operator’s decision making process. We believe R2 discourages a Balancing Operator from deploying contingency reserves for events that may have an adverse impact on reliability but do not fall under the proposed definition of a Reportable Balancing Contingency Event nor occur during an EEA Level 2 or 3. Events of this type could include, but are not limited to, low ACE due to unexpected load changes, schedule changes, and/or slow unit response that are adversely affecting Interconnection frequency or transmission flows approaching IROL’s due to contingencies that have occurred in an adjacent balancing area. Current R2 language: Except during the Responsible Entity’s Contingency Event Recovery Period and the Responsible Entity’s Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over each Clock Hour, at least equal to its Most Severe Single Contingency. Recommended R2 language: Except during the Responsible Entity’s Contingency Event Recovery Period and the Responsible Entity’s Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over each Clock Hour, at least equal to its Most Severe Single Contingency ADD: ,averaged over each Clock Hour. C)We request the SDT to consider adding a sub-requirement to address the concern that R2 potentially could discourage a Balancing Operator from deploying contingency reserves for events that may have an adverse impact on reliability but do not fall under the proposed definition of a Reportable Balancing Contingency Event nor occur during an EEA Level 2 or 3. Suggested R2.1 language follows: ADD: R2.1 Contingency reserves will be

restored within the 105 minute recovery + restoration periods following deployment of contingency reserves for a reliability need. D)The SDT is requested to consider developing a draft RSAW to accompany this draft standard. The OC Review Group feels it is critical to have the draft RSAW to go along with the draft standard. E)We respectfully request the SDT review the “averaged over each Clock Hour,” when an event occurs within the last portion of the hour. The standard should include language that states that average hourly contingency reserves will not fall below average hourly MSSC for more than three consecutive clock hour. Summary: We believe that the suggested modifications above would allow Balancing Operators to utilize the appropriate resources at their disposal to mitigate events that may have an adverse impact on Interconnection reliability while establishing a continent-wide contingency reserve policy in accordance with Order 693 and avoiding increased costs to our customers. 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 the SERC Reliability Corporation, or its board or its officers.
Individual
Catherine Wesley
PJM Interconnection
Yes
PJM would like to thank the SDT for their hard work and perseverance in developing this standard as well as the opportunity to provide comment. The changes made to the definition of Reportable Balancing Contingency Event, while adding to complexity, are positive changes. However, due to the language in R1.3, the definitions need to clearly define and differentiate the start of the Balancing Contingency Event and the start of the Reportable Balancing Contingency Event compliance period. This differentiation is especially important for BCA’s that may begin with a controlled unit runback but turn into an RBCA when the unit trips offline. Likewise, the changes made to Requirement 1, while adding to complexity, are positive changes. Additional clarity may be achieved by restructuring the requirement in tabular form with the simplest scenario listed first. While we agree with the intent of Requirement 2, we continue to believe that the proposed language will have unintended consequences from the intended objective and could inject an unnecessary element into the Balancing Operator’s decision making process. We believe R2 discourages a Balancing Operator from deploying contingency reserves for events that may have an adverse impact on reliability but do not fall under the proposed definition of a Reportable Balancing Contingency Event nor occur during an EEA Level 2 or 3. Events of this type could include, but are not limited to, low ACE due to unexpected load changes, schedule changes, and/or slow unit response that are adversely affecting Interconnection frequency or transmission flows approaching IROL’s due to contingencies that have occurred in an adjacent balancing area. If there was to be a commodity measure in the standard, there are changes to the current proposal that could relieve the aforementioned concerns. Proposal #1: The standard could include language that states that contingency reserves shall be restored within the 105 minute recovery + restoration periods following deployment of contingency reserves for a reliability need. Proposal #2: Alternatively, the standard could include language that states that average hourly contingency reserves shall not fall below average hourly MSSC for more than three consecutive clock hours. Regardless of which of these proposals are adopted, the hourly contingency reserves should be in reference to average hourly MSSC. This will add clarity for BA’s that have a dynamic MSSC that changes in real-time. We believe that the suggested modifications above would allow Balancing Operators to utilize the appropriate resources at their disposal to mitigate events that may have an adverse impact on Interconnection reliability while establishing a continent-wide contingency reserve policy in accordance with Order 693 and avoiding increased costs to our customers.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
1) The current draft’s definition and then practical inclusion of Most Severe Single Contingency, has retained the “MW output” term, yet now includes the concept of lost power import schedules. This “MW output” term worked fine when the original NERC Policy and then Standard addressed only loss

of Generation within a BA’s footprint. Because sudden cut of an import schedule is unlikely to result in a sudden decline in net energy export, AECI now seeks clarity for the “MW output” term’s meaning: 1a. Loss of net generation MW output (likely to be the common BA perception)?, OR 1b. Loss of MW output from the BA’s footprint, and disregarding scheduled interchange?, OR 1c. Algebraic decline of inadvertent interchange (Net-Actual-Interchange minus Net-Scheduled-Interchange), and disregarding Interchange frequency change?, OR 1d. Algebraic decline of ACE which typically includes the BA frequency-bias factor applied to any sudden frequency change? 2) This current draft of NERC Reliability Standard BAL-002-2’s requirements R1 and R2, in conjunction with EOP-003-2 R1, can cause BAs to unnecessarily shed load, or to be instructed by an RC to do so, when there is no real risk to BES reliability, and even when Interconnection frequency is quite high, in direct opposition to the more refined reliability-based BAL-001-2 Standard now awaiting FERC approval. See AECI’s suggestions #3 and #4. 3) Due to unintentional consequences, this current draft as well as its predecessors, has a serious scalability issue. Both large BAs and now large RSGs, necessarily provisioned to allow small BAs some equitable relief under BAL-002, allow and even encourage creation of artificially over-sized entities, to lower the business-related impact of the BAL-002 Standard yet: 1) at a potentially reduced value to overall BES reliability, should they get even larger, or 2) no real added-value to BES reliability for smaller BAs having been forced into RSGs or large Market –based BAs. So, unless BAL-002-2 is removed as a Reliability Standard altogether, AECI proposes two options for a simplified version of this standard, based upon our own experience of obligations within a reasonably sized RSG: 3a. 5% of each BA or RSG’s largest online unit’s capability, yet with consideration for multiple constricted areas within their footprint being held to the same metric. 3b. 0.8% of each BA’s or RSG’s net online generating capability, or net load, whichever is greater. (AECI favors this as being simple, close to what the large BAs and RSGs are carrying, and with added benefit of being dispersed within footprints containing smaller BAs.) 4) Draft BAL-002-2 is now fundamentally a fair business practices standard. All reliability-related issues historically addressed within BAL-002 predecessor’s requirements or guidelines, now appear to be better met by the overlapping effects of NERC Requirements found within EOP-001 (Adequate planning and provision for resources to weather the Most Severe Single Contingency event), BAL-001-2 (Ongoing degree of reliability-related Energy and Frequency Imbalance), and BAL-003 (Frequency-response reflecting amount of Spinning-reserve being carried). This explains why SDT Requirement R2 consideration to allow for up to 5 “failing” hours within a calendar month, was refuted by argument that such allowance could be abused by Entities deliberately coinciding their deficiencies with peak-hours, a fair business-practice argument, but then countered by BAL-001-2's essentially precluding such behavior. So BAL-002-2 is now a candidate for NASB adoption, as they deem necessary, with removal from the BAL standards. 5) Provided this SDT elects to not entirely remove BAL-002-2 from the NERC Reliability Standard set or simplify per Options 3a or 3b above, AECI does favor the SERC OC WG's suggested addition of ", averaged over each Clock Hour" to then end of R2, as well as R2.1, as well as their part "E)" suggestion for allowing reserves to drop below MSSC for no more than three consecutive clock hours. Due to current draft complexities, AECI also favors an RSAW being developed by the SDT ASAP.
Group
DTE Electric
Kathleen Black
Agree
MISO
Group
ACES Standards Collaborators
Jason Marshall
Yes
(1) The addition of Part 1.3 clarifies that the requirement does not apply when the contingency exceeds its Most Severe Single Contingency (MSSC). Its inclusion obviates the need for the second sub-bullets of R1 under the first and second main sub-bullets and that begins with “Further reduced by the magnitude…” These sub-bullets are not needed because they only apply when the Balancing Contingency Event exceeds the MSSC and Part 1.3 is clear that the main requirement does not apply in this situation. (2) We continue to believe that the thresholds established in the Reportable

Balancing Contingency Events are arbitrary. There is no supporting evidence for the values that were selected. The companion background document does include a brief discussion of the thresholds but it only discusses why 100 MW was not selected and it does not discuss why the thresholds were selected. What is the justification that the threshold for the Eastern Interconnection cannot be above 900 MW for example? (3) The Reportable Balancing Contingency Event definition is fundamentally flawed. The last sentence contradicts the statement that the lower threshold is 80%. The lower threshold is in fact no greater than 80% and is set by the responsible entity upon written notification to the Regional Entity. If the value will be variable, this should be stated directly in the first sentence of the requirement to avoid the definition contradicting itself. (4) The Reportable Balancing Contingency Event definition should be further modified to avoid unnecessary compliance burdens and paperwork. There is no need to notify the Regional Entity in writing before changing the lower reporting threshold. The Regional Entity has no documented process in the standard to prevent the change from occurring so communicating it to the Regional Entity is an unnecessary compliance burden. The responsible entity should only be obligated to document it. The Rules of Procedure allow the Regional Entity to request this type of data in several other ways. They could even request it as part of an annual self-certification as an example. FERC has stated that definitions are considered standards, and this part of the definition could be viewed as meeting Paragraph 81 criteria because it is administrative in nature. In particular, it meets criterion B4 because it requires reporting to the Regional Entity which has “no discernible impact on promoting the reliable operation of the BES.” (5) The definition of Pre-Reporting Contingency Event ACE Value requires additional justification to change the pre-disturbance calculation from an average of 10 to 60 seconds of ACE data prior to the disturbance to a 16-second interval. There is no explanation of this in the background document and we cannot support such a change without a justification for how it supports reliability. Furthermore, the definition is not consistent with other reliability standards, such as BAL-005-0.2b which requires ACE calculation on at least a six-second basis. A BA using a six-second sample rate could be viewed as being out of compliance if an entity used either two (12 seconds) or three (18 seconds) samples since they cannot use exactly 16 seconds of data. Furthermore, using only two or three samples could lead to unrealistic averages particularly if there are any spurious data points. What does an entity do if a scan was skipped or there was a data spike? More samples would make it less likely for this to be an issue. (6) While the standard has been modified to provide more flexibility in the use of Contingency Reserve, there still is not enough flexibility and the standard could have unintended consequences for reliability. For example, the definition of Contingency Reserve limits the use of Contingency Reserve to only contingent events. This would prevent the BA from using Contingency Reserve for other reliability purposes such as to respond to inadequate schedule ramping when other units don’t ramp as expected. A BA should be free to call upon Contingency Reserve to reduce a negative ACE for reliability support regardless of whether it is caused by a contingency or some other event. (7) The “Additional Compliance Section” potentially conflicts with the definition of Contingency Reserve. Since “Additional Compliance Section” would allow the use of Contingency Reserve to meet other standards as required this would be a conflict if the use of Contingency Reserve was to comply with another standard not involving a contingency. The definition of Contingency Reserve restricts the use to only contingencies. For example, the IRO-005-3.1a R5 compels the BA to utilize all resources to relieve emergency conditions regardless of whether they were caused by a contingency or not. (8) The data retention required for the current versions of this standard is too long. BAs submit quarterly data to their regional entities, so they should not be required to retain three years worth of data. While the standard will no longer compel this quarterly reporting, this practice is unlikely to change. At the very least, compliance staff should be consulted to determine if this will continue to be the practice. We strongly recommend the drafting team collaborate with NERC compliance to develop an RSAW and other compliance guidance. If the RSAW was developed with the standard, it would facilitate the discussion with industry of how much data is needed to be retained. (9) The data retention section of the standard exceeds what is allowed in the NERC Rules of Procedure, Section 3.1.4.2 of Appendix 4C. This section specifies that “the audit period begins the day after the End Date of the prior Compliance Audit...the audit period will not begin prior to the End Date of the previous Compliance Audit.” Since BAs are only audited approximately every three years, the data retention period of up to four years (current year, plus three previous calendar years) exceeds the three year audit period. (10) Thank you for the opportunity to comment.
Individual
Gregory Campoli

New York Independent System Operator
Agree
The NYISO supports the comments and questions raised by both the IRC/SRC and NPCC RSC.
Group
SPP Standards Review Group
Robert Rhodes
Yes
In BAL-002-2: We would like to thank the drafting team for the clarification provided in the definition of Reportable Balancing Contingency Event regarding the intent of ‘sudden’. We also thank the drafting team for adding the clarification on events larger than an entity’s MSSC as provided in Requirement R1.3. In the Background Document: On Page 5, in the 3rd line of the 2nd paragraph under Contingency Reserve, change ‘complimented’ to ‘compliment’. In the 6th line of the same paragraph, capitalize ‘reserve’ in ‘Operating Reserve’. On Page 11, in the 10th line of the 2nd paragraph under the Background and Rationale section for Requirement 2, delete the ‘s’ on ‘suites’. In the last line of the last paragraph on Page 11, replace ‘real-time’ with ‘Real-time.’ In the CR Form 1: Replace ‘Exemp’ with ‘Exempt’ in the title on the Exemption worksheet. Use of terms: Demand-Side Management – In the definition of Contingency Reserve in the standard and in the Contingency Reserve section of the Background Document, use the NERC Glossary of Terms Demand-Side Management in lieu of Demand Side Management. Clock Hour – In Measure M2, be consistent with the use of Clock Hour. In some uses the term is capitalized and in others it isn’t.
Individual
Russel Mountjoy
Midwest Reliability Organization
Agree
Midcontinent Independent System Operator (MISO)
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Agree
Duke Energy
Individual
Richard Vine
California ISO
Agree
ISO/RTO Standards Review Committee
Group
Bonneville Power Administration
Jamison Dye
Yes
- Definition R1 refers to ‘Reporting ACE’ and there is no accompanying definition of this term. - BPA recommends further clarity and explanation for the sudden unplanned outage of a transmission facility, and sudden restoration of known load used as a resource that causes an unexpected change to responsible entity’s ACE. - BPA recommends leaving in the Unexpected Failure of Generation to start language in the definitions section.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No

ERCOT ISO is generally supportive of the IRC SRC comments, the BAL-002-2 standard, and appreciates the work the SDT has done on the standard and the opportunity to comment. ERCOT ISO suggests that the 800 MW threshold for ERCOT be removed from the definition of Reportable Balancing Contingency Event for the ERCOT single-BA area Interconnection and have the calculation of MSSC apply to single-BA area Interconnections.