Consideration of Comments

Project Name: 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls | BAL-002-2

Comment Period Start Date: 7/7/2015

Comment Period End Date: 8/20/2015

Associated Ballot: 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls BAL-002-2 IN 1 ST

There were 33 sets of responses, including comments from approximately 87 different people from approximately 63 different companies representing 8 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Please provide any issues you have on this draft of the BAL-002-2 standard and offer a proposed solution for those issues.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

1. Please provide any issues you have on this draft of the BAL-002-2 standard and offer a proposed solution for those issues.	
Dan Roethemeyer - Dynegy Inc. - 5 -	
Answer Comment:	Our entity, as a Generation only BA, currently under BAL-002-1 uses “Coordinated adjustments to interchange schedules” as the primary method of meeting the standard. The new standard BAL-002-2 Rev 7 is not clear if “Coordinated adjustments to interchange schedules” will be allowed. We feel the language needs to be clarified as to what is allowed as contingency

reserve since “The provision of capacity that may be deployed by Balancing Authority” is vague.
As drafted, the standard states the requirement, not how to meet the requirement. The proposed language tells how to meet the requirement. As drafted, the standard does not prohibit any adjustments that correct ACE.

Response:

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5 –

Answer Comment:

No Comment just want to vote Yes

Response: **The SDT thanks you for your affirmative response.**

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 – MRO

Answer Comment:

No issues

Response: **The SDT thanks you for your affirmative response.**

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment:

none

Response: **The SDT thanks you for your affirmative response.**

Emily Rousseau - MRO - 1,2,3,4,5,6 – MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment:

We appreciate that the drafting team has removed the zero defect component of the standard and that the current draft acknowledges that reserves should be deployed to address multiple reliability issues.

Our primary concerns are the following:

R1.1.2, reporting events should be covered in the compliance section of the standard, not a requirement. Please refer to NERC's paragraph 81 criteria "B4 Reporting", which notes that documentation should not be included in a standard as a requirement.

The standard should retain a simple quarterly report form rather than creating forms for each report. The reasoning the drafting team gave for not adopting this recommendation is not substantiated. It just says that VSLs for small entities will be Severe without providing examples. Performance is performance. Size has no impact in this standard. VSLs are just a starting point in the enforcement process. Regional enforcement staff will determine the seriousness and risk associated with a violation. We can provide a simple example of a form that would work for this standard. It would keep reporting simple and provide NERC the data it needs for its State of Reliability Report.

R1 part 1.2 does not require a report to be submitted. Instead it requires the calculation to be on the referenced form. This ensures all entities subject to compliance utilize the same methodology for each event. The SDT disagrees with the inclusion of a quarterly report in a standard. If NERC or the Regions desire quarterly reporting it should be done under their data collection process.

While not primary concerns, the standard could be clearer if the following changes were made:

Under the term for a Balancing Contingency Event, a change in ACE is only mentioned for the loss of generation, not the other resource losses. It's probably not necessary to mention change in ACE as a resource loss is a resource loss.

The SDT believes that a change in ACE is in the appropriate location in the definition. The SDT agrees with you that a resource loss is a resource loss.

The last two and a half lines of the MSSC definition are unnecessary. The definition can be:

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority.

Some RSGs allow for members to participate in the group on an event-by-event basis. The additional language allows for this flexibility.

For the definition of Contingency Event Recovery Period, since small events can happen in sequence (such as runbacks or individual generator trips on a combined cycle plant), the recovery period should not start with the initial decline as the BA may not know they are in a DCS event until the event has played out. Recommend changing the wording be changed to "begins at the time when ACE reaches the reportable threshold of a Balancing Contingency Event, and extends for fifteen minutes"

There is not an ACE threshold for a reportable event. The reportable event is established by the amount of the resource loss. For the purposes of a runback, if the MW threshold is not reached in a single minute then it would not be considered a reportable event. Therefore, the start of the event would be the minute in which the threshold is met not the start of the runback.

We can provide a redline of the standard that has minor housekeeping edits that would simplify wording upon request.

Response:

Russel Mountjoy - Midwest Reliability Organization - 10 -

Answer Comment:

MRO supports the intent of BAL-002-2 however, MRO does not support the addition of R1.2. R1.2 is purely adminstrative in nature and reporting should not be part of a reliability Standard.

R1 part 1.2 does not require a report to be submitted. Instead it requires the calculation to be on the referenced form. This ensures all entities subject to compliance utilize the same methodology for each event. The SDT agrees that reporting should not be part of a standard.

Response:

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 –

Answer Comment:

As a stakeholder of MISO, we are supporting their comments.

Please refer to the SDT response to the comments submitted by MISO.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 –

Answer Comment:

We have three primary concerns with this standard:

- R2 is ambiguous as to what is meant by “review and maintain annually, and implement”. While it looked like the drafting team moved away from a zero defect standard (where reserves must be > MSSC every hour), the RSAW implies that the ERO interprets this wording differently. The drafting team’s intent should be clear in the measure that operators should not be discouraged to deploy reserves when needed, but they do need an approach to be notified when reserves are low and a means to replenish them.

The SDT agrees that the RSAW could be interpreted in such a manner to not meet the intent of the requirement. The RSAW is being modified to clarify the necessary compliance elements for the next posting.

- The Paragraph 81 criteria note that reporting and filling out paperwork should not be a requirement, yet there is such a requirement to “document all Reportable Balancing Contingency Events using CR Form 1”. Rather than a requirement, this should be explained in the compliance section of the standard.

The SDT disagrees with the characterization that this is a Paragraph 81 issue. The Requirement R1 part 1.2 requires a specific calculation in the form. This ensures all entities subject to compliance utilize the same methodology for each event. There is not a reporting requirement in the standard.

• We do not agree with the move away from simple quarterly reporting. While there is stray wording in Order No. 693 on compliance for single events, this does not preclude submitting a quarterly report. As it is, NERC will likely still request this data for "State of Reliability Reporting" and then auditors will ask to see the reports again as well.

The SDT disagrees with the inclusion of a quarterly report in a standard. Adding a requirement for quarterly reporting would be a Paragraph 81 issue. If NERC or the Regions desire quarterly reporting it should be done under their data collection process.

As the current standard is structured, it looks like it will cause BAs to request EEAs whenever reserves are reduced to address day to day balancing issues. Even though there is no change in reliability, the likely step increase in EEAs will likely trigger other concerns, the solution for which would likely be another standard. The standard should be clearer in the measure and supporting information that reserves can be drawn down, but the BA needs an approach to replenish them or call EEAs if unable to do so.

The SDT is unsure as to what is meant by your comment. There is no requirement in the proposed standard for reserves to be held on a real-time basis, addressing an issue of contention within the current standard. Instead there are requirements addressing correction of ACE, to plan for reserves on a day-ahead basis, and to restore reserve following a Reportable Balancing Contingency Event.

We had additional comments that would make the standard simpler or clearer. These have been previously sent to the drafting team.

Response:

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 – NPCC

Answer Comment:

Hydro-Quebec TransEnergie supports NPCC comments.

Please refer to our response to the comments submitted by NPCC.

Response:

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment:

The IESO thanks the SDT for revising the previous R2 to remove those parts that contain confusing language and are deemed unnecessary.

However, we are still unable to find the need and reliability benefit of R3 which requires a BA to restore its Contingency Reserve to at least its Most Severe Single Contingency (MSSC) before the end of the Contingency Reserve Restoration Period given the need to meet R1 except under the specified conditions which include events occurring during Contingency Reserve Restoration Period. By virtue of meeting R1, a BA must have Contingency Reserve that equals or exceeds MSSC at all time (expect under the conditions in Part 1.3). Replenishing Contingency Reserve is thus an implicit requirement in R1. Having an explicit requirement for replenishing reserve in R3 will expose Responsible Entities to potential double jeopardy, is unnecessary and adds no reliability value.

As an illustration, failing R1 except under certain conditions which include the Contingency Reserve Restoration period implies that a BA didn't have

sufficient contingency reserve to meet the ACE recovery requirement stipulated in R1. Failing R3 means a BA did not restore (or have) sufficient contingency reserve except during the Contingency Reserve Restoration period. Note that an event may or may not occur at a time when a BA does not have sufficient CR, so a BA may fail R3 alone but not R1. However, the reverse is not true. A BA that fails R1 will most likely (if not invariably) also fails R3, hence the double jeopardy.

Having only R1 would suffice as this requirement will drive a BA to recover or have sufficient CR except under certain conditions.

We therefore once again propose that R3 be removed.
While the SDT appreciates your position, we believe that R3 is significantly different than R1. R1 requires an entity to recover from an event within a 15 minute window. R3 requires an entity to essentially modify their day-ahead plan to address the circumstance in the real-time and to address the next contingency if it were to occur. There is no expectation to carry reserves during the Contingency Reserve Restoration Period. Additionally, Requirement R3 carries forward the intent of the current BAL-002-1 Requirement R6.

Response:

Rob Vance - NB Power Corporation - 5 -

Answer Comment:

We also submitted our comments through NPCC. We feel the intent of the 3rd bullet of Requirement 1.3.1 is to ensure that all required reserve up to the MSSC required reserve value is used prior to the waiver of Requirement

	1.1 becoming available. The current wording suggests that you need only deplete reserves to a value less than the MSSC required reserve amount and the waiver will be enabled. This would wave the normal requirement to restore ACE even while leftover reserve is still available. We feel the wording "the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency" should be changed to read "the Responsible Entity has depleted its Contingency Reserve by at least the amount of reserve required for its Most Severe Single Contingency". The SDT disagrees with your view because all of the three bullets must be met not just the third bullet. In addition, the bullets in R1 part 1.3 are listing the system condition at the time of the Reportable Balancing Contingency Event not following the Reportable Balancing Contingency Event. As an example, if you are not in the EEA prior to the loss, the waiver would not apply. Also, we feel the same R1.1 waiver should apply for multiple contingencies that use all of the required reserve regardless of whether a declared Energy Emergency Alert is in effect. An EEA is used only if there are already insufficient reserves to meet requirements or an expectation of not meeting requirements. In the case of a non-emergency normal restoration that doesn't require a declared emercy but becomes difficult near the end of the Contingency Event Recovery Period, the time it takes to declare an emergency may extend the actual recovery beyond the Contingency Event Recovery Period thereby creating a non-compliance. The exemption in the current BAL-002-1 standard (see section 1.5 of part D of the standard) does not require a previously declared emergency. If necessary, a declaration of an Energy Emergency Alert can be made ASAP ***after*** a restoration has failed to meet the Contingency Event Recovery Period requirement. The SDT agrees with your premise. Please refer to Requirement R1 Part 1.3.2 where the SDT excluded multiple events which exceeds MSSC.

Response:

David Kiguel - David Kiguel - 8 –

Answer Comment:

The SDT should be commended for its work in putting forward this draft. However, there are a number of areas where the draft can be improved before adoption by NERC.

1. R1.3 is confusing. Instead of detailing what the Responsible Entity must do, it extends to details on what is NOT subject to compliance. Results based standards must focus on what reliability objectives are to be achieved rather than what is not subject to compliance. All after "however, it is not subject to compliance with Requirement 1, part 1.1…." does not belong in the requirement. It could be part of the Compliance Section.
While the SDT appreciates your position, from past experience information contained outside of the requirement is not enforceable and cannot be used for determination of compliance. Therefore, any exclusions must be contained in the requirements.

2. Sub-Requirement R1.2 refers to documentation and as such is administrative in nature, i.e. does not contribute to Reliability. Furthermore, it seems to meet Criterion B4 of the Paragraph 81 Criteria.
The SDT disagrees with the characterization that this is a Paragraph 81 issue. The Requirement R1 part 1.2 requires a specific calculation in the form. This ensures all entities subject to compliance utilize the same methodology for each event. There is not a reporting requirement in the standard.

3. Requirement R3 seems to contain obligations that are related to/repeated

from R1. The obligation to restore Contingency Reserve should be merged into R1.

While the SDT appreciates your position, we believe that R3 is significantly different than R1. R1 requires an entity to recover from an event within a 15 minute window. R3 requires an entity to essentially modify their day-ahead plan to address the circumstance in the real-time and to address the next contingency if it were to occur. There is no expectation to carry reserves during the Contingency Reserve Restoration Period. Additionally, Requirement R3 carries forward the intent of the current BAL-002-1 Requirement R6.

Response:

Jeri Freimuth - APS - Arizona Public Service Co. - 3 –

Answer Comment:

R1.2. should not be included in the requirements section. This administrative function would violate FERC P81 as administrative in nature. Also, the process or form could change.

The SDT disagrees with the characterization that this is a Paragraph 81 issue. The Requirement R1 part 1.2 requires a specific calculation in the form. This ensures all entities subject to compliance utilize the same methodology for each event. There is not a reporting requirement in the standard.

R1.3. AZPS is concerned that the NERC Glossary of Terms only allows a BA or LSE to be in an EEA. And EOP-002-3.1 R7 and R8 have the Balancing Authority requesting to be declared in an EEA. If a Balancing Authority were in an RSG, that would make the RSG the Responsible Entity under BAL-002-

2. If the BA was experiencing and requested an EEA, does this transfer exception allowed in R1.3 to the RSG as not being subject to compliance? If a Balancing Authority is experiencing an EEA event under which its contingency reserves have been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance. The RC should have gone through all steps prior to an EEA.

R2. If we understand correctly, this requirement is extending the requirement of EOP-011-1 R2 by reference. We do not believe it is advisable to include a requirement that adds to the elements of another requirement in a separate standard. It raises tangential questions such as "does this Operating Process have to be RC-approved as the Operating Plan does?" There is no relation to EOP-011-1 R2. While this requirement does reference an Operating Plan, it is not the same Operating Plan referenced in EOP-011-1 R2. Instead, the Operating Plan referenced in BAL-002-2 may be the same Operating Plan required under R4 of TOP-002-4, specifically part 4.4.

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 – WECC –

Answer Comment:

BPA is in agreement with the proposed standard. However, BPA believes there should be a clarifying comment in requirement R1. In R1, sub-requirement 1.1, following the second bullet, BPA would like the standard to state:

The recovery value for any Balancing Contingency Event(s) that occurs

Response:	***during the Contingency Event Recovery Period shall be the recovery value for the initial event.*** While the SDT understands your comment, there is no required recovery value for a Balancing Contingency Event in this standard. Recovery values are only used for Reportable Balancing Contingency Events. Please refer to CR Form 1 to determine how the recovery value is determined for multiple events.
Richard Vine - California ISO - 2 -	
Answer Comment:	1. The High VSL for R2 in the proposed BAL-002-2, as well as auditor guidance in the proposed BAL-002-2 RSAW, could be interpreted to require Contingency Reserve to be > MSSC at all times other than when deployed in response to a Balancing Contingency Event. However, in the Western Interconnection BAL-002-WECC-2 allows clock-hour averaging to determine if Contingency Reserves were adequately maintained. How will this apparent conflicting methodology be reconciled if BAL-002-2 is passed? The SDT agrees that the RSAW could be interpreted in such a manner to not meet the intent of the requirement. The RSAW is being modified to clarify the necessary compliance elements for the next posting. The Contingency Reserve requirement in R2 is only for an Operating Process that determines and plans for Contingency Reserves. There should not be any real-time measurement for Contingency Reserves in R2, unlike in the WECC Regional Standard. Therefore, there is no conflict.

2. The definition of Contingency Reserve in the proposed BAL-002-2 indicates this is capacity that may be deployed to respond to a ***Balancing Contingency Event***. However, R3 states "Each Responsible Entity, following a ***Reportable Balancing Contingency Event***, shall restore Contingency Reserve to at least its Most Severe Single Contingency before the end of the Contingency Reserve Restoration Period...". The proposed standard does not identify how long an entity has to return Contingency Reserve following deployment for a ***Balancing Contingency Event (i.e. -*** not "Reportable").

There is no recovery period required for a Balancing Contingency Event nor is there reserve restoration period associated with a Balancing Contingency Event. However, if a Reportable Balancing Contingency Event occurs the required time frame for reportable events will be reviewed to determine if the Balancing Contingency Event impacts the compliance responsibility. As an example, a Balancing Contingency Event that occurs two hours prior to a Reportable Balancing Contingency Event will not reduce the response requirement for the Reportable Balancing Contingency Event but a Balancing Contingency Event that occurs one hour prior to the Reportable Balancing Contingency Event may. Please refer to Requirement R1 Part 1.3.2.

Response:

Spencer Tacke - Modesto Irrigation District - 4 –

Answer Comment:

I am recommending a NO vote for the following reasons:

1. A specific percent change in ACE (Area Control Error) needs to be specified in the definition of ***Reportable Balancing Contingency Event***, where it states ***"…sudden decline in ACE based on EMS scan rate…"*** (on page 3).

The reporting threshold is based on the size of the resource loss not the change in ACE. Therefore, no specific change in ACE is necessary.

2. Using arbitrary MW definitions for each major Interconnection (on page 4) under the same section on the definition of a ***Reportable Balancing Contingency Event***, may lead to inconsistent results, as the MW values actually needed are dynamic and based on the amount of load and on-line generation at the time of the disturbance or contingency event.
The MW thresholds are based on a statistical evaluation of historical events in each interconnection and their impact on system frequency. Please refer to the Background Document posted with this standard. Your proposal would make it more difficult to determine the point at which an event becomes a Reportable Balancing Contingency Event. The SDT utilized conservative numbers in order to provide the System Operators with the necessary information to operate the grid while maintaining compliance.

3. Under the ***Contingency Reserve Restoration Period*** definition on page 4, the ***period*** should be ***30 minutes*** instead of ***90 minutes*** in order to be consistent with the NERC TOP-004 (Transmission Operations) Standard.
There is no direct coorelation between the time frames in the two standards. Your proposal would reduce the current restoration which has proven to provide an adequate level of reliability over the years.

4. Under ***the Rationale for Requirement R1*** on page 7, the phrase ***"..returns its Area Control Error (ACE) to defined values…"*** should include a locational reference to the actual ***defined values*** (i.e., what are they and where can they be found ?).
The defined values are determined in Requirement R1 Part 1.1. The Rationale boxes are not enforceable and are moved to another area of the standard when the standard is filed.

Thank you.

Sincerely,

Spencer Tacke

Senior Electrical Engineer

Modesto Irrigation District

209-526-7414

Response:

Anthony Jablonski - ReliabilityFirst - 10 –

Answer Comment:

ReliabilityFirst votes in the Affirmative because the standard helps to better ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. ReliabilityFirst offers the following comments for consideration:

1. Requirement R1, Part 1.3.1

i. There is a disconnect between the lead in Part 1.3.1 and the third bullet. The lead in states "the Responsible Entity is:" and the third bullet states "the Responsible Entity has depleted…". As one can see, there is a double use of the term “the Responsible Entity”. RF recommends the following language for consideration:

1.3.1 the Responsible Entity:

• [is] experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and

• [is] utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and

• has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

The SDT agrees with your comment and has modified the language.

Response:

Edward Magic - SCANA - South Carolina Electric and Gas Co. - 5 –

Answer Comment:

R 1.1.2 Reporting should not be a requirement.

R1 part 1.2 does not require a report to be submitted. Instead it requires the calculation to be on the referenced form. This ensures all entities subject to compliance utilize the same methodology for each event.

R2 M2 Contingency Reserves can and should be deployed for reasons to include loss of resources temporarily till mitigation measures are implemented less than MSSC. M2 does not make it clear that reserves can be used for any other resource loss less than MSSC. It appears you have to provide data that you had reserves >= MSSC each hour.

The BAL-002-2 RSAW posted further supports our primary concern “Review the evidence and verify that the entity had available Contingency reserves equal to, or greater than its Most Severe Single Contingency” Suggest the wording be revised “Confirm the applicable Entity met the Contingency Requirement for Reportable Balancing Contingency Event(s)”

The SDT agrees that the RSAW could be interpreted in such a manner to not meet the intent of the requirement. The RSAW is being modified to clarify the necessary compliance elements for the next posting. Further Requirement R2 and Measure M2 have no bearing on utilization of Contingency Reserve. Rather it is only a requirement to plan to have Contingency Reserve as part of you Operating Plan.

Response:

Joseph Bencomo - LG&E and KU Energy LLC - 1,3,5,6 - SERC,RFC -

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6

Answer Comment:

These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): LG&E and KU Energy, LLC and PPL Electric Utilities Corporation. The PPL NERC Registered Affiliates are registered in two regions (RFC and SERC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

Comments

Clarity is needed as to whether or if a BA that is a member of an RSG but does not request RSG assistance for a specific BCE is considered the Responsible Entity. The “active status” language used in 4.1.1.1 is unclear.

Suggested solution – Modify language in 4.1.1.1 to:

4.1.1.1. A Balancing Authority that is not a member of a NERC registered Reserve Sharing Group is the Responsible Entity.
The SDT appreciates your comment. However, the proposed language provides the flexibility for RSGs to allow members to participate on an event-by-event basis as some RSGs currently allow.

The proposed draft 7 requires reporting and compliance evaluation of each individual Reportable BCE. Quarterly reporting and evaluation of Reportable Events on a quarterly basis has worked well and should be continued.
The proposed standard does not require any reporting. The language as drafted is proposed to address a directive from FERC Order 693 Paragraph 354 which requires compliance based on individual events.

BAL-001-2 becomes enforceable 7/1/2016, R2 (BAAL performance) will incent the appropriate BA/RSG action to a Reportable BCE without forcing

action that could be contrary to interconnect frequency stability. BAL-001-2 has negated the need for BAL-002-2.
Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

The language in R1.3 related to an exemption from R1.1 needs to be applicable to R1 and R3.

An entity experiencing an EEA (or any of the other exemption scenarios in R1.3) should not be required to restore ACE as stated in R1.1, document the Reportable BCE as per 1.2 or restore Contingency Reserves to MSSC within the Contingency Restoration Period as stated in R3.

For a Responsible Entity experiencing an EEA, compliance with BAL-002-2 R3 is not consistent with actions required under the EEA.

Suggested solution – Modify language in 1.3 to:

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 parts 1.1 and 1.2 and R3 if:
The entity experiencing any of the scenarios in Requirement R1 Part 1.3 is exempt from compliance for Requirement R1 Part 1.1.

The exemption in Requirement R1 Part 1.3 is applicable only to Requirement R1 Part 1.1. Entities that experience events that meet the exemption for

Requirement R1 Part 1.1 should still be able to document the Reportable Balancing Contingency Event s under Part 1.2. The definition of Contingency Reserve addresses your concern related to Requirement R3 by allowing firm load readied to be removed from the system, thus allowing the load to count as Contingency Reserve.

Response:

Lee Pedowicz - Northeast Power Coordinating Council - 10 – NPCC -

Group Name: NPCC--Project 2010-14.1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1

Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Answer Comment:

With the requirements as written, the Responsible Entity should include the Reliability Coordinator. As defined in the NERC Reliability Functional Model Version 5 for the Reliability Coordinator, **Balancing operations**:

"**Balancing operations.** The Reliability Coordinator ensures that the generation-demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-demand-interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability."

The SDT does not believe that this standard should include any requirements on the Reliability Coordinator. The Reliability Coordinator is governed by requirements located in the IRO standards.

Consider incorporating Requirement R3 into Requirement R1 by adding the following Part 1.4:

1.4 Restore its Contingency Reserve to at least its Most Severe Single Contingency before the end of the Contingency Reserve Restoration Period.

The SDT discussed this and determined that the restoration of ACE and the restoration of Contingency Reserve are two separate and distinct actions. Therefore the SDT believes that these two actions should be covered under two separate requirements.

Regarding the wording used to define the **Most Severe Single Contingency (MSSC),** as it reads now the MSSC is defined as "The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss ...".

	The process used to find the MSSC uses system models and does allow the modelling of contingencies. For clarity, suggest revising the wording in the definition. The models themselves neither identify contingencies nor are contingencies “maintained in” them. Suggest eliminating the words “…as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority’s area that is not part of a Reserve Sharing Group…”or replacing the words “identified and maintained in the system models within” with the following: “identified using system models maintained within…”. The SDT has made the necessary modifications. We feel the time requirement to declare an EEA of any level prior to 1.1 being waived is an unnecessary operations burden during the Contingency Event Recovery Period. It could result in an entity being non-compliant because complete recovery is delayed by the time it takes to go through the "declaration" process. We feel the new standard is adding an exposure to non-compliance because of the need for the RC to declare an emergency prior to the waiver of the ACE correction requirement in Part 1.1. Within NPCC there are entities that fill both the RC role that declares the EOP-002-3 Energy Emergency Alert level, and the BA role that BAL-002-2 will apply to. The SDT believes that the proposed requirement under Requirement R1, Part 1.1 is not an undue burden because the use of an EEA is not applicable to this standard and is not appropriate as a solution for complying with Requirement R1 Part 1.1. If an entity is not in the EEA prior to a loss, the waiver of R1 Part 1.1 would not apply. In addition, the wording in the third bullet of Part 1.3.1 (Part 1.3.1 needs identification in the draft) needs clarification. For example, if your MSSC is a resource loss of 400 MW, this Part’s wording would suggest that the depletion of "Contingency Reserve to a level below its Most Severe Single Contingency" would refer to a value of less than 400 MW. You might deplete

your reserves by 250 MW and still have 150 MW remaining to meet another contingency after the initial event which may be sufficient and not require a waiver. We suspect that the intention is that all of the MSSC determined value of required reserve is depleted before the waiver is allowed.

The intention of the bullet is that if an entity utilizes its Contingency Reserve such that it dips below its MSSC, regardless of the magnitude, the entity can no longer fully respond to meet Requirement R1 if its MSSC occurs. Therefore, Requirement R1 Part 1.3.1 allows an exemption from compliance if all of the three bullets are occurring at the same time.

Response:

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 – SPP –

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Carl Stelly	Southwest Power Pool Inc	SPP	2
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
Jes Gray	Omaha Public Power District	MRO	1,3,5

Answer Comment:

We would suggest to the drafting teams developing coordinated efforts with the Alignment of Terms Standards Draft Team (Project 2015-04). The collaborative efforts would pertain to the revised and newly proposed terms in BAL-002-2 which would help ensure that these terms are included in both the NERC Glossary of Terms as well as the Rules of Procedure for proper alignment (which can be addressed in Phase II of their project). Of course, this collaborative effort would take place once NERC's BoT and FERC approves the proposed terms and standard pertaining to this current project. If a proposed definition is also in the Rules of Procedure, the drafting team will work with NERC to ensure that alignment is maintained going forward.

Our review group also noticed that the drafting team uses the acronym 'RE' several times (second paragraph on page 4) in the Rationale for Contingency Reserve Definition section of the standard. We will make the assumption that you are referring to the term 'Responsible Entity'. However, we would suggest either using it as an appositive with the term or removing it from the document completely. We feel that some confusion will arise amongst the industry on what 'RE' is being referred to. For example, 'RE' could refer to 'Regional Entity' or 'Registered Entity'.
The SDT has made the appropriate modifications.

In the Rationale section for Requirement R1, the drafting team mentions "The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language". We would ask the drafting team to provide more clarity on what direction BAL-002-2 is going in reference to the EEA. The rationale states that the drafting team has developed proposed language. Can we assume this proposed language is currently in the standard and if so, will this language match up with the NERC's process changes to the EEA levels (which hasn't been developed yet)? The next question would be….will these process changes be vetted through the voting process or will it be the law of the land?

The SDT has made the necessary clarification to the Rationale Box. Please note that the proposed EEA changes were developed as part of the EOP-011-1 standard currently filed at FERC.

Our group understands that the conversation pertaining to the retirement of BAL-002-2 is in the distant future. However, we have the concern that there are current documentation in place that helps serve the industries needs in reference to the MSSC. With that being said, we feel that BAL-002-2 brings confusion and redundancy to the industry and we would suggest that the drafting team take into consideration the retirement of this standard.
Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

Finally, we would like to suggest to the drafting team once the terms and standards have been approved by the NERC BoT and FERC to follow up on this project and ensure that the RSAW be properly aligned with this standard.
The SDT agrees that the RSAW could be interpreted in such a manner to not meet the intent of the requirement. The RSAW is being modified to clarify the necessary compliance elements for the next posting.

Response:

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 – RFC -

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Christina V. Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Answer Comment:

The SRC agrees with the intention of the SDT draft 7 posting to:

· Provide the risk based parameters (ACE range, Recovery period, Restoration period) for responding to a Balancing Contingency Event (BCE);

· Ensure that the definition of Most Severe Single Contingency (MSSC) does not include more than one resource;

· Ensure that the definition of BCE does recognize the possibility of the loss of more than one resource;

· Eliminate draft 6’s hourly obligations; and

· Clarify that shedding load is not an expected action in order to maintain reserves.

The SRC does not agree with proposed standard wording that:

· Links MSSC to BCE; and

· Links Contingency Reserves (CR) to Disturbance Control Standard (DCS) compliance.

The SRC proposes clarifying modifications to definitions for:

· Balancing Contingency Events;

· MSSC;

· Contingency Event Recovery Period; and

· The EEA level referenced in R1.3.1

The SRC again asks the SDT to remove the language within draft 7's proposed CR requirement that ties DCS compliance to the use of CR.

The SRC has characterized its comments in three classifications: those proposed to facilitate clarity; those proposed to ensure that the focus of requirements remains on reliability; and those proposed to address other concerns.

Revisions Proposed To Facilitate Clarity

The SRC would ask that the SDT to redraft the requirements in more direct terms. Phrases like "demonstrate recovery" in the requirement section of the standard can be construed ambiguously and a clear reliability requirement omits unnecessary words and directly defines the obligation.

In particular, the SRC suggests that the linkage between R 1.1 and R1.31 is a source of ambiguity within the standard because:

· Requirement R1.1 defines the target ACE correction (range of recovery);

· Requirement R1.3 defines Contingency Reserve deployment;

· Sub-Requirements of R 1.3 then introduce exceptions for **R1.1** (*i.e.*, R 1.3.1 and R 1.3.2).

This organization does not allow readers and entities responsible for compliance and direct correlation between specific defined obligations and the proposed exemptions. To facilitate clarity, the SRC offers two recommendations. The first recommendation preserves much of the current, draft language while the second recommendation provides more streamlined language:

1. Retaining current draft language:

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

• zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event, or,

• its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if: **1.3.1** the Responsible Entity is:

Unless:

· the responsible entity:

• is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher; is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan; or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency .

or,

· the following subsequent event(s) occur:

1.3.2 the Responsible Entity experiences:

•	multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Even;, or

•	multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

1. *More direct version*:

R1. Unless the Responsible Entity is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher, is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, , the Responsible Entity experiencing a *Reportable Balancing Contingency Event* (RBCE) shall return its ACE to:

· Zero within the *Contingency Event Recovery Period* if the Responsible Entity’s Pre-RBCE ACE Value were positive or equal to zero; or

· Its Pre-RBCE ACE Value if the Responsible Entity’s Pre-RBCE ACE Value were negative

Where a Balancing Contingency Event exceeds the responsible entity’s MSSC or multiple Balancing Contingency Events occur within the Contingency Event *Restoration period* of the 1st RBCE, the responsible entity shall deploy contingency reserves, but such response shall not be subject to Requirement R1:

Revisions proposed to ensure that the focus of requirements remains on reliability

The SRC asserts that the primary focus of BAL-002 should be reliability (ACE recovery) with less focus be given to the specific process regarding how to meet the reliability requirement. The current draft appears to link economic sharing arrangements (Contingency Reserves) to a reliability requirement and, therefore, precludes the use of more effective processes to meet the reliability requirement. The SRC cautions the SDT against mandating the use of a process where such usage would be inappropriate from both a reliability and cost efficiency perspective when other processes are available For example, as written, draft 7 could preclude the use of Demand Side Management (DSM) as Contingency Reserves (in contradiction of Order 1000), and restricting DSM to Emergencies only. For these reasons, the requirements should be re-focused on what needs to occur for reliability – not how such activities are performed.

The SRC does recognize the SDT's attempt to address the issue of maintaining reserves designed to preserve serving load verses the issue of shedding load to preserve reserves and that it makes no sense to shed load to maintain reserves that are designed to protect load from being shed.   Additionally, the SRC questions the need for the proposed Requirement R2 (*i.e.*, the requirement to have a method to compute MSSC). Such

requirement is administrative in nature as it mandates a creation of a procedure, an implementation process for that procedure, as well as a mandate to "have" a market service to calculate MSSC. The sentence in draft 7 can be read as ether:

· an annual obligation to compute MSSC and to use that annually-computed MSSC in system operations, and

· carry an equivalent amount of reserves for that year

or

· develop a plan to explain how to compute MSSC and review that plan every year

· implement the computation (the implication is that the plan will introduce the time frame for updating MSSC)

· carry an equivalent amount of RC (for as long as the plan states)

The definition of MSSC is axiomatic and does not require a formal procedure. The only plausible justification for having such a plan is mandate self-imposed rules regarding when to compute MSSC; how to apply that calculation; and for how long. Given the ambiguity in draft 7's R2, either approach can be justified. Such ambiguity would not serve reliability. As an example, if draft 7 really did intend linking MSSC to an annual value, and in doing so lock-in a minimum reporting value (80% of MSSC), then what could occur is that small BAs can have a minimum reportable value that is larger than any unit that is operating on a given day – in effect - exempting them from ever reporting. On the other hand, if draft 7 really did intend to provide flexibility to the BAs, a number of questions arise: Is this a daily scheduling function, or a continuous operating function? Is the objective fixed or does it depend on what is operating at the given time? Accordingly, the current approach could be interpreted broadly and variably and should be revised as it does not appear to be directly focused on or facilitating reliability.

Revisions Proposed to Address Other Concerns

The SRC suggests the following comments and/or revisions for the SDT's consideration:

1. Delete the phrase "within system constraints" in Requirement R1. Because BAs are not responsible for system constraints (that's the role of TOP), the inclusion of this phrase connotes that a BA can be held responsible for exacerbating a SOL problem, even if the BA had no knowledge of the limit and was taking actions to comply with its obligations. The requirements should respect current roles and responsibilities of the various functions and, currently, the TOP is responsible for directing the BA in this regard.

2. The standard has a reporting requirement, but does not include a reporting timeframe. Therefore, the most conservative assumption would be that reporting is on and "individual event" basis. For draft 7, the SDT rejected quarterly reporting based on a non-relevant paragraph in Order 693.

354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters.

The SRC requests that the SDT explain its correlation between the reporting requirement and P 354 and requests that the SDT clarify the timing of any required reporting. Additionally, the SRC is unclear as to how "the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure." Upon review, it appears that values for entities are calculated on a % of recovery whether applied to an individual event or quarterly performance – accordingly the severity of a violation would still be correlated to overall performance for some time period. The SRC requests that the SDT re-evaluate its explanation and provide additional clarification.

1. The Draft 7 definitions of MSSC and BCE do not resolve the issue of BCE being greater than the MSSC because Draft 7 continues to link the definitions of MSSC and BCE. The SRC believes MSSC is an a priori / actual state value while BCE is an a posteriori event/experience. The SRC agrees with the SDT that MSSC can never be more than one resource otherwise it would not be a "single contingency." BCE on the other hand can (as the current definition indicates) include the impacts of the loss of more than one resource. To address this concern, the SRC offers the following comments and revisions.

Draft 7 definition of MSSC:

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Draft 7 definition of 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 one minute or less.

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's 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 unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Given the above definitions, the SRC concludes that the SDT correctly wants to ensure that MSSC include large interchange schedule imports as well as large generators. The definition of BCE does that (see sub item B). The draft 7 definition of MSSC relies on the definition of BCE to ensure that such interchange gets considered. The problem is that the foreword of the BCE definition includes the phrase "or any series of such otherwise single events." That addition makes it virtually impossible to quantify / limit one single resource amount for an MSSC.

The SRC would suggest that Draft 7 definition of Event be retained, but that the definition of MSSC be redrafted. The SRC suggests:

MSSC is the MW capacity of the single largest resource scheduled to operate for a given day’s peak load. The resource may be a generator (Maximum Continuous Operating Capacity) or a Firm Interchange scheduled import.

This revision:

· Changes the MSSC definition from being linked to a Balancing Contingency Event of undefined size, to linking MSSC to an easily identified single resource capacity/expectation.

· Can be used to provide clarity concerning why and how the amount of CR can be set to a daily MSSC; and how and why every CBE can be “reported” upon without being subject to the DCS objectives for an MSSC.

The Draft 7 definition CR does not define what CR is, but rather defines what CR may be used for. Moreover, the definition’s use of the phrase “provision of capacity” requires further explanation to clearly delineate between the concept of “provision of capacity” in the Operating Planning environment (meaning to request that resource be made available to serve load) versus the “provision of capacity” in the compliance/operating environment (meaning the amount of energy that was produced at the request of the BA). An additional issue with the first sentence is that, as written, it specifically excludes the use of those reserves to serve firm customer load. To address this concern, the SRC offers the following comments and revisions.

Draft 7 definition of Contingency Reserves

Draft 7 definition of Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

• is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

The SRC suggests that the issue of CR and reserves in general requires an Industry-wide review; and the SDT in its introduction to its Response to Comments propose the ERO conduct such a review prior to making a decision on a final ballot. The review would be used to decide if:

· Reserves were linked to day ahead scheduling in the sense that "reserve" capacity over and above the capacity scheduled to meet a peak load. This concept was referenced in the original Policy 1 – Generation Control and Performance, (dated Feb 1, 1997) at romanette ([i]) If CR were viewed as scheduled available system capacity there would be no issue, because then the measurement of reserves would be focused on the planned capacity for the day. Once that capacity is synchronized it can be used for any and all purposes.

Response: **Please refer to the response to these comments at Page 76.**

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Answer Comment:

We would like to thank the SDT for their work on this proposed revision to BAL-002-1 and the opportunity to provide comments.

Definitions

MSSC: As written the MSSC definition is linked to and dependent on the definition of a Balancing Contingency Event. In doing so an RE must determine its MSSC based on a Balancing Contingency Event, or series of events including imports, separated by one minute, that have not occurred. As long as the definition of MSSC is dependent on the definition of a BCE, we suggest that MSSC is incalculable and propose the change below.

Most Severe Single Contingency (MSSC): The loss of a single Element as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, or the sudden loss of an import, or the sudden restoration of a Demand that was used as a resource, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).
The SDT does not believe that your structural changes provides any additional clarity to the proposed definition to the proposed definition.

Contingency Reserve: As written, the criteria for allowing readiness to reduce Firm Demand in Contingency Reserve is ambiguous. We suggest adding clarifying language to clearly state when the readiness to reduce Firm Demand will be accepted as Contingency Reserve.

We propose the following changes for clarity.

Contingency Reserve: The resource capacity, measured in MW, above that serving Firm Demand, that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

• is experiencing a Reliability Coordinator declared Energy Emergency Alert level where an energy deficient BA is not able to maintain minimum Contingency Reserve requirements, and

• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
The SDT believes that your suggested modification to the first bullet appears to duplicate the second bullet while adding a potential burden to compliance.

Requirement 1:

We understand the intent of the SDT, however, R1.3 states that an RE must deploy Contingency Reserve for all Report Balancing Contingency Events regardless of whether there is a need to deploy Contingency Reserve to comply with R1.1. Recovery is often accomplished through frequency responsive and regulation resources. Additionally, R1.3 as written could be

	interpreted to mean that an RE shall deploy ALL available Contingency Reserve, which could be well above MSSC, for ALL Reportable Balancing Contingency Events which could have an adverse impact on Interconnection frequency and BES reliability. For example, using the PJM minimum synchronized reserve requirements (100% of MSSC, or approximately 1400MW deployed via All-Call) and regulating reserves (+/- 700MW during peak hours); language that suggests a mandatory deployment of Contingency Reserve could result in well over 2100MW, responding to a 900MW reportable event. This response could be much higher since synchronized reserves are typically much greater than the 1400MW requirement and regulation alone could result in 1400MW of response. We also recognize that the BAAL limits defined in the recently approved BAL-001-2 ensure that an RE will take all available actions to respond to a Reportable Balancing Contingency Event and support Interconnection frequency. For compliance with Requirement R1 Part 1.1 response is determined by your ACE within the first 15 minutes regardless of how recovery is accomplished. Requirement R1 Part 1.3 describes the process for when events combine to be greater than MSSC and provides exclusion from compliance for Part 1.1. However, exclusion from compliance for Part 1.1 does not allow an entity to avoid responding at all to a large event. Note that Part 1.3 does not require all Contingency Reserves be activated. Additionally, we suggest that the phrase “within system constraints” should be removed because BA’s are not responsible for system constraints; that being the role of the TOP. The TOP standards address system constraints and the TOP is responsible for directing the BA in this regard.

Accordingly, we propose the changes below.

1.3. respond to all Reportable Balancing Contingency Events, which may include the deployment of Contingency Reserve, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3.1 the Responsible Entity is:

• experiencing a Reliability Coordinator declared Energy Emergency Alert Level where an energy deficient BA is not able to maintain minimum Contingency Reserve requirements, and

• utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and

• the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

The drafting team agrees the BA is not responsible for determination of system constraints. However, the following selected list of Requirements from Standards, either currently enforceable or approved by the NERC Ballot Body, NERC Board of Trustees and filed at FERC requesting approval for future enforcement, makes it clear that a Balancing Authority can't perform their duties reliably without being knowledgeable of system constraints.

TOP-001-3 R20
TOP-002-2.1b R4, R5, R6, R7, R9 and R10
TOP-002-4 R4
TOP-003-1 R1.2

TOP-003-3 R2, R4 and R5

Finally, removing the phrase would make a requirement to activate all Contingency Reserves, regardless of any negative impacts to the Bulk Electric System for large events. The drafting team discussed this concern and determined that the BA should only activate the level of reserves that could be safely used without creating reliability issues on the grid.

Requirement 2:

We propose the following changes to Requirement 2 to add clarity.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have available Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
The SDT has made this clarifying modification.

Requirement 3:

With the addition of Requirement 3, either R1.2 should be removed from the standard or the CR Form 1 should be modified to demonstrate Contingency Reserve restoration including subsequent Balancing Contingency Events that may occur within the Contingency Event Restoration Period so that compliance to a Reportable Balancing Contingency Event can be demonstrated with a single document.
Thank for your suggestion. The SDT believes that compliance with Requirement R1 and compliance with Requirement R3 are two different

actions. Requirement R1 requires a specific calculation methodology. Requirement R3 compliance may be demonstrated with various methods.

Response:

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2 -

Answer Comment:

ISO New England does not agree with the SDT's position that an EEA Level 3 is necessary in order to support an exemption from R1. If this were elevated to Level 3 that would imply shedding load in order to maintain reserves and ISO New England understands that this was not the intent.

EOP-011 states that a Level 2 EEA is "The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority." meaning all available resources are in use serving load; and " An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements." which given the first instance can only be accomplished through arming for load shed to cover the reserves if a contingency were to occur. In the alternative, this would mean shedding actual customer load to maintain reserves before the contingency actually occurs, which is not in the best interest of Reliability.

The SDT disagrees with your comment. EEA Level 3 is titled "Firm Load interruption is imminent or in progress". The SDT believes that if an entity is utilizing firm load for its Contingency Reserve then interruption of firm load is imminent. Therefore, an entity utilizing firm load for Contingency Reserve would be in an EEA Level 3.

Response:

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 –

Answer Comment:

ERCOT commends the drafting team on their efforts to improve BAL-002-2. However, it has concerns and recommendations regarding the proposed modifications. ERCOT supports and incorporates into its comments by reference the comments submitted by the ISO/RTO Council Standards Review Committee. Additional concerns and recommendations are described below by Requirement. Proposed revisions are *italicized*.

Please refer to our response to the ISO/RTO Council Standards Review Committee, beginning on page. 76.

1. Definitions – ERCOT reiterates its previous comments regarding the Reportable Balancing Contingency Event thresholds contained within the definition of a Reportable Balancing Contingency Event. ERCOT believes that the introduction of various, differing thresholds creates unnecessary complexity and would propose a 1000 MW threshold for its interconnection as such threshold aligns with the current practice. Further, ERCOT reports other, smaller events to NERC and its Regional Entity through different mechanisms and, therefore, with differing reporting thresholds, the same event can be reported to NERC multiple times under different requirements. Accordingly, since the threshold limits relate only to reporting and associated documentation, ERCOT respectfully submits that lowering the reportable event thresholds does not provide any benefit to reliability.

The MW thresholds are based on a statistical evaluation of historical events in each interconnection and their impact on system frequency. The SDT utilized conservative numbers in order to provide the System Operators with the necessary information to operate the grid while maintaining compliance. Please refer to the Background Document posted with this standard.

2. ERCOT reiterates the need to revise Requirement 1 to provide obligations in more direct terms and with additional clarity and reiterates its comments regarding burdensome and administrative nature of the individual reporting requirement contained within Requirement R1.2 for individual Reportable Balancing Contingency Events. Such reporting does not benefit reliability and could obscure trends or other characteristics that would be obviated by reporting over a longer time period. Perhaps the SDT could consider a time period that is shorter than quarterly, but clarify that reporting is not on an individual basis triggered by individual events.

R1 part 1.2 does not require a report to be submitted. Instead it requires the calculation to be on the referenced form. This ensures all entities subject to compliance utilize the same methodology for each event. The SDT disagrees with the inclusion of a quarterly report in a standard. Adding a requirement for quarterly or any other time period for reporting would be a Paragraph 81 issue. If NERC or the Regions desire quarterly reporting it should be done under their data collection process.

3. Requirement R2 –ERCOT respectfully submits that, as proposed, Requirement R2 adds potentially onerous and unnecessary administrative processes and documentation to what has, historically, been a simple, well-established process regarding identification of the MSSC and the procurement of appropriate contingency reserves. To simplify this requirement while retaining the reliability-related aspects of its objective, ERCOT offers the following revisions for the SDT's consideration:

Each Responsible Entity shall document and implement its criteria for identification of MSSC and its processes for review of MSSC and for procurement of contingency reserves greater than or equal to the identified MSSC, which shall be reviewed no less than annually.

Measure 2 could then be modified as follows:

Compliance may be achieved by demonstrating that:

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

• *Criteria for determination of the MSSC;*

• Documentation of its processes for identification of the MSSC and procurement of contingency reserves equal to or greater than its Most Severe Single Contingency; and

· Evidence to indicate that the processes have been reviewed and maintained annually.

ERCOT suggests this alternative because the identification of MSSC is subject to criteria and are part of an overall process to be performed. Further, the proposed requirement presumes a particular structure for responsible entity's compliance processes and procedures that designates the "how" of meeting the requirement instead of the "what." The proposed revision preserves the objective of the proposed Requirement 2 while ensuring that the requirement is results-based and respectful of the various administrative structures established within various entities to administer compliance-related documentation and processes.

The SDT does not believe that the requirement is telling an entity how to comply but rather requiring a process to address the reliability issue. Also, the SDT has modified the requirement to provide additional clarity.

ERCOT thanks you for the opportunity to comment upon the proposed

Revisions to BAL-002-2. Should the ERO wish to provide additional guidance regarding the mix or management of Contingency Reserves, it should consider the development and publication of a Reliability Guideline.

The SDT thanks you for your suggestion. The SDT has developed an Operating Reserve Guideline approved through the NERC OC. The guideline document can be found at the following link. http://www.nerc.com/comm/OC/Pages/Reliability-Guidelines.aspx

Response:

Ben Engelby - ACES Power Marketing - 6 –

Group Name: ACES Standards Collaborators - BARC Project

Group Member Name	Entity	Region	Segments
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3

Answer Comment:

(1) We applaud the SDT on its efforts to clarify the language of the standard and respond to our previous comments. We continue to believe the SDT is heading in the correct direction during the development of this

standard. However, we still have concerns regarding the language, scope, and implementation plan.

Thank you

(2) We are disappointed that the SDT has not responded or addressed our previous concerns regarding the "Most Severe Single Contingency" definition. From the definition, we believe the applicability reference should be removed entirely. We recommend the definition should read "A Balancing Contingency Event, as identified by the Responsibility Entity and maintained in its system models, that would result in the greatest loss of resource output at the time to meet Firm Demand and export obligations, excluding those export obligations for which Contingency Reserve obligations are being met by a Sink Balancing Authority." We also recommend the removal of the MW measurement, a unit of power, as a Balancing Contingency Event is a moment in time.

The term Responsible Entity is not defined in the glossary and therefore cannot be used in the definition. The drafting team also believes that the measurement in MWs is appropriate in that the process uses MWs to determine the amount of loss for a DCS event. There was no other proposed means to measure the event so it is unclear what would be measured without using MWs. For these reasons, the SDT has not made the suggested changes.

(3) Likewise, we wish the SDT would further clarify this standard's applicability. We understand the need to address the instance when a BA fails to meet the membership requirements of a Reserve Sharing Group (RSG). We recommend that Section 4.1.1.1 should be split as follows, "4.1.1.1 A Balancing Authority is the Responsible Entity that is not a member of a Reserve Sharing Group" and "4.1.1.2 A Balancing Authority that is a

member of a Reserve Sharing Group and is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or the governing rules for the Reserve Sharing Group."

Some RSGs allow for members to participate in the group on an event-by-event basis. As drafted the language is more specific than that proposed. Therefore, the SDT has not accepted the proposed modification.

(4) The SDT needs to address our previous comments regarding the "Reportable Balancing Contingency Event" definition. We recommend the removal of "Prior to any given calendar quarter..." from the definition, as it implies the need for an additional requirement for Responsible Entities to coordinate an exception from the rest of the definition which is based on a percentage of the MSSC or an Interconnection-based amount. Furthermore, we continue to believe that the thresholds in the definition are arbitrary, and ask that the drafting team provide a technical basis for these values. In many cases, the values selected are below the median values identified in Attachment 1 of the background document. By not documenting the more frequently occurring values annually, we fear this could cause issue later on in the standard development process. We recommend moving the identification of these values, and supporting background for their selection, to an attachment within the standard, similar to the approach taken in NERC Standard BAL-001-2.

The SDT disagrees with removing the language related to changing the reportable threshold from the definition. Without that language, it would prohibit any modification from the 80 percent of MSSC. The drafting team believes that any modification to the reporting threshold must be made prior to the event, not after the event. In order to determine the appropriate reportable threshold, documentation is necessary if an entity decides to change this threshold.

The reporting thresholds are supported by the referenced background document. With the reference to the background document, the commenter should understand that the values are not arbitrary but determined by the statistical evaluation of historical events. Once the evaluation was done, the drafting team determined the average of the medians and determined that the values should be rounded to an even 100 value to make the reporting threshold easily remembered by operating personnel.

(5) Under certain situations, a Responsible Entity may not be aware of the significance of a Balancing Contingency Event. For the definition of Contingency Event Recovery Period, the SDT should clarify that the recovery period should not start with the initial decline of resource output, but the instance when ACE reaches the reportable threshold of a Reportable Balancing Contingency Event and fifteen minutes thereafter.

There is not an ACE threshold for a reportable event. The reportable event is established by the amount of the resource loss. As an example, if a runback occurred and the MW threshold is not reached in a single minute then it would not be considered a reportable event. Therefore, the start of the event would be the minute in which the threshold is met not the start of the runback.

(6) The SDT should consider moving all standard-specific definitions to the NERC Glossary of Terms.

Once the standard is adopted by the NERC BOT, the definitions would be moved to the NERC Glossary of Terms.

(7) We feel the SDT is overcomplicating the language of Requirement R1. We concur that clarification is needed in the instance when a Balancing Contingency Event follows a single Reportable Balancing Contingency

Event. However, embedding a reference to identify what is and isn't required within the same requirement is cumbersome. We recommend moving the embedded reference to another requirement and identify the Contingency Event Recovery Period only applies to a single event.

While the SDT understands your concern we do not agree with the desire to separate this into two requirements. Separation of Requirement R1 into two requirements would likely cause a violation of one requirement that could result in violation of both requirements.

(8) We have concerns with the VSLs identified for Requirement R1. We agree with the SDT's conclusions that the measured contingency reserve response and required recovery value of Reporting ACE, when is adjusted for other Balancing Contingency Events that occur during the Contingency Event Recovery Period, are mathematically equivalent. However, the VSLs are based on one approach while the spreadsheet is based on the other. We recommend the SDT select one approach and use it consistently throughout the standard.

The SDT reviewed the VSL and CR Form 1 calculations and find them to be consistent. Therefore, no changes have been made to either the VSLs or CR Form 1.

(9) We acknowledge the SDT for its response to our previous comments regarding Requirement R1.2. However, we still feel that a requirement for documenting events in a spreadsheet is administrative in nature, and could even be classified as a P81 requirement, as its violation would never result in a harm to BES reliability, especially at a Medium level risk to operations. If an entity only identifies the MW loss and date and time of the event, yet leaves the rest of the form blank, would this result in a violation? As written, the answer would be no, although an incomplete form would not meet the

	intention of the SDT to provide consistent reporting. We recommend the SDT identify the criteria needed for uniform reporting in a separate attachment to the standard and remove administrative tasks that meet Paragraph 81 criteria. The SDT disagrees with the characterization that this is a Paragraph 81 issue. The Requirement R1 part 1.2 requires a specific calculation in the form. This ensures all entities utilize the same methodology for each event. There is not a reporting requirement in the standard. The SDT believes that a form that is partially filled out may be sufficient to meet compliance with Requirement R1 Part 1.2, although this would depend on circumstances. However, an incomplete form will show a failure to correct ACE to its pre-event level which would be a violation of Requirement R1 Part 1.1. The SDT disagrees with moving the criteria to a separate attachment and having the entities create their own calculation of compliance. This would put every entity at risk of violation due to the need to support the calculation made to demonstrate compliance prior to any compliance evaluation. By providing the form referenced in Requirement R1 Part 1.2, industry essentially needs to provide one number from the form to prove compliance. (10) We recommend the removal of “all Reportable Balancing Contingency Events” as a condition listed in Requirement R1.3. This condition is already referenced in R1. We believe rewording Requirement R1.3 to read “…deploy Contingency Reserve, within system constraints, except when not subject to compliance with Requirement R1 part 1.1 if…” would still satisfy the requirement. For compliance with Requirement R1 Part 1.1 response is determined by your ACE within the first 15 minutes regardless of how recovery is accomplished.

Requirement R1 Part 1.3 describes the process for when events combine to be greater than MSSC and provides exclusion from compliance for Part 1.1. However, exclusion from compliance for Part 1.1 does not allow an entity to avoid responding at all to a large event. Note that Part 1.3 does not require all Contingency Reserves be activated.

(11) In reference to Requirement R2, we question the need to review an Operating Plan, as such action is already implied with an Entity is "maintaining" their plan. We believe the language identified should be aligned with the language listed within NERC Standard EOP-010-1.

The SDT appreciates your comment but believes that use of both words provides an additional level of clarity. We agree that it is possible to accomplish both with one action.

(12) If the intent of the SDT to have Responsible Entities use CR Form 1, then we recommend adding its use in Measure M3 and in the RSAW for R3. A Responsible Entity is already able to use the form to demonstrate its deployment of Contingency Reserve, within system constraints, then it should be able to reuse the form to demonstrate the restoration of Contingency Reserve within the Contingency Reserve Restoration Period.

Thank for your suggestion. The SDT believes that compliance with Requirement R1 and compliance with Requirement R3 are two different actions. Requirement R1 requires a specific calculation methodology. Requirement R3 compliance may be demonstrated with various methods.

(13) We disagree with the VSLs identified for Requirement R3 that measure the percentage of Contingency Reserve restoration. The requirement identifies the required time that such restoration must be completed. We recommend replacing with the form "The Responsible Entity restored less

than x% but at least y% of required Contingency Reserve following the conclusion of the Contingency Event Restoration Period."

The SDT believes that your suggested wording allows unlimited time for an entity to restore its Contingency Reserve.

(14) We feel that the bullets of Requirement R1.1 and Requirement R3 are redundant in reference to "any Balancing Contingency Event that occurs during the Contingency Event Recovery Period." We suggest removing the redundant bullets in Requirement R1.1 for clarity, and instead expand Requirement R3 to include a reference to magnitude.

The SDT believes the removal of the bullets would require an entity to recover its ACE within 15 minutes regardless of other events occurring within that 15 minutes. The SDT also believes that compliance with Requirement R1 and compliance with Requirement R3 are two different actions. Requirement R1 requires a specific calculation methodology. Requirement R3 compliance may be demonstrated with various methods.

(15) We caution the SDT that references to the term "Reporting Area Control Error" in the rationale for Requirement R1 goes into effect July 1, 2016. The Implementation Plan references that the standard would go into effect six months after FERC approval. Since this term is critical to the definition of "Pre-Reporting Contingency Event ACE Value", we recommend an update to the Implementation Plan to July 1, 2016 or later as the effective date.

The SDT understand your concern. However, based on our review of the timing, this is not an issue.

(16) We observe a typographical error within the Implementation Plan

regarding the definition of Most Severe Single Contingency. We recommend the removal of the "that is not part of a Res area" reference. The definition should then read "…within the Reserve Sharing Group (RSG) or a Balancing Authority's area that not part of a Reserve Sharing Group…"

Thank you. The SDT has made the necessary correction.

(17) We recommend the SDT fix the title page of the background document to include the document's title, "Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document."

Thank you for your comment. The title was lost during the translation to a PDF document. The SDT will make the necessary correction.

(18) We thank the SDT for this opportunity to comment on this standard.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 –

Answer Comment:

Texas RE noticed the VSL for R1 does not address R1.3. The language for R1.3 should be included.

Requirement R1 Part 1.3 defines exceptions; therefore the SDT does not believe that it would be appropriate to create a VSL.

Texas RE noticed the VSL for R2 does not address the review annually portion of the Requirement. VSL should be changed to include "maintain annually".

The SDT has modified the lower VSL to clarify that "maintain" meant "maintain annually".

Texas RE recommends the VSL for R3 should include Requirement language "at least its Most Severe Single Contingency".
The SDT believes that as written ("…required Contingency Reserve…") the VSL provides sufficient clarity.

Response:

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 –

Answer Comment:

Now that BAL-001-2 is approved, there will be another standard driving a BA to take corrective action in certain situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency.

Example of loss of generation in the middle of the night:

If the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response required by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2.

Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

Response:

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 – FRCC-

Answer Comment:

Now that BAL-001-2 is approved, there will be another standard driving a Balancing Authority to take corrective action in certain situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency. One example would be if there is a loss of generation in the middle of the night. If the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2.

Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

Response:

Jamie Lynn Bussin - NaturEner USA, LLC - 5 –

Answer Comment:

I. Introduction

NaturEner USA, LLC and its subsidiaries ("NaturEner") largely support the proposed changes to BAL-002-2, which move the standard towards a performance-based measure of disturbance control response.

While NaturEner largely supports the proposed changes to BAL-002-2, NaturEner believes the standard can be, and should be, even further improved. Specifically, NaturEner recommends that the definition of "Balancing Contingency Event" should be further modified to explicitly include as a qualifying event an unpredicted loss of generation capability. While generator-neutral, the explicit inclusion of this type of event has particular and extreme importance to variable (i.e., renewable) generation, which due to the current inherently imprecise nature of forecasting, unavoidably experience such events at times. The sole reason that NaturEner has abstained in this balloting process, rather than voting affirmative, is because NERC's proposed definition does not explicitly include as a qualifying event an unpredicted loss of generation capability.

NERC's suggested changes to BAL-002-2 propose the following definition of 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 one minute or less.*

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's 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 unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

NaturEner recommends that the definition should be revised to add a fourth clause to subsection A.a.:

iv. *unpredicted loss of generation capability.*

Revising that definition as suggested is consistent with the underlying reasons for specifying certain events as Balancing Contingency Events, as NaturEner's suggested revision reflects sudden and unavoidable events affecting the grid, and also supports the efficient and effective deployment of resources and the integration of renewable resources. Moreover on a broader basis, though such a revision to the definition is not required for reserve sharing groups to include unpredicted loss of generation capability as a qualifying contingency event under which reserve contingencies can be called upon, such a revision to the definition can only help ongoing efforts to encourage reserve sharing groups who have not yet approved such occurrences as qualifying events to do so now.

II. Reasoning

NaturEner collectively is the owner of three wind farms, the Glacier Wind 1 wind farm, the Glacier Wind 2 wind farm, and the Rim Rock wind farm, as well as two wind-based balancing authorities, NaturEner Power Watch, LLC and NaturEner Wind Watch, LLC.

NaturEner takes wind power forecasting extremely seriously, and has invested significant resources to improve our ability to accurately schedule our generation onto the grid. However, there are some weather events that are extremely difficult to forecast and can cause wind generation units to lose generating capability quickly and unexpectedly. These can result from events such as a sudden change in wind direction due to changing weather regimes or localized effects, or from other complex weather interactions which are not well-captured by state of the art forecasting techniques. Though these events are outside of our control and can result in a sudden and large unpredictable loss of generation, such events are currently not recognized as qualifying events in some regional reserve sharing groups.

For conventional generating units in the west, there are few limitations on the cause or frequency of qualifying contingency events. This is consistent with the underlying purpose and rationale of a reserve sharing group - that there are various extreme events which are unpredictable, unavoidable, and can impact reliability. By pooling the resources of participating Balancing

Authorities, reliability can be maintained without requiring individual Balancing Authorities to carry 100% of MSSC in reserves. This is beneficial to the grid, because it avoids costly over-procurement of capacity, while still ensuring the reliability of the system as a whole. The low likelihood that multiple contingencies will occur at the same time means that this shared capacity can be relied upon to be sufficient. Large rapid loss of wind (and solar) events are similarly consistent with the underlying purpose and rationale of a reserve sharing group, in that they there are extreme events which are unpredictable, unavoidable, and can impact reliability. Moreover, if they are appropriately defined and evaluated over a geographically diverse area, they are unlikely to occur at the same time.

The exclusion of extreme loss of wind or solar events from qualifying contingency events leads to at least two negative consequences. First, because the calculation of the resource requirements do not consider regional diversity, the sum of the resource requirements calculated at each individual Balancing Authority-level are much larger than what would be calculated at a system-wide level, leading to systematic over-procurement. Second, due to the increase in capacity resulting from this approach, wind integration tariffs have been implemented in some Balancing Authorities, chilling the ability of new renewable generation to come online in some regions. In contrast, the Midwest ISO has been progressive in implementing market initiatives and programs to enable flexibility in its system and has not needed to increase its reserve capacity as its renewable penetration has increased. The Southwest Power Pool is also a system which has been recognized as a leader in variable integration, and its reserve sharing group makes no limitations on what the cause of a qualifying event is, only that it should be a loss of generation greater than 50 MW. Also with respect to two different weather-related events which result in a loss of generation, members of the Northwest Power Pool (NWPP) are currently allowed to call contingency reserves for high-speed cutouts and for temperature extremes.

With the conversion of BAL-001 to the BAAL standard, the standard approach of using a "CPS2 Analysis" to determine the reserves required to operate reliably will become obsolete. At this point, the timing issue which NaturEner raised in its January 26, 2015 FERC comments to the proposed rulemaking regarding BAL-001 (FERC 20150126-5252, RM14-10) will become more important (in fact, FERC in its Order in that RM14-10 proceeding, suggested that NaturEner raise the subject matter set forth in these comments in this NERC proceeding (151 FERC ¶ 61,048, at page 26, footnote 72)). In a CPS2 analysis, the monthly ACE is evaluated to ensure that reserves are sufficient such that 90% of the 10 minute periods are within L10, regardless of the magnitude. In a BAAL analysis, the ACE will have to be evaluated such that any single 30 minute period should not exceed the BAAL limits. Due to the timing constraints of 15 minute scheduling and the 30 minute BAAL timer, there will be some ACE events which cannot be resolved by modifying interchange schedules. To ensure that a RBC violation will not occur, BA reserves will need to be carried which can resolve the largest such event which could be observed. This will result in an increase in the inefficient deployment of capacity and related transmission reservations in order to maintain compliance for unpredicted loss of generation capability events unless such events qualify as recognized balancing contingency events.

The risk of unnecessary reserve build-outs and holdbacks may be alleviated to some extent if a regional energy imbalance market ("EIM") is implemented, because the market would settle every 5 minutes, thereby resolving the time constraints outlined in our previous comments. However, RBC will come into effect prior to any operational EIM in the WECC. This may in fact result in a system-wide increase in capacity required to be held in reserve and unnecessary reservation of related transmission, and their associated costs.

	Even if and when an EIM is present, however, it still will likely not adequately resolve the problems from unpredicted loss of generation capability unless designed appropriately. It may still cause individual Balancing Authorities to procure more reserve capacity and related transmission than is required to reliably operate the system as a whole. In discussion regarding implementation of an EIM, a resource sufficiency (RS) methodology is being considered by the NWPP to verify that EIM participants enter the scheduling hour with sufficient resources. The work being done in this respect is thoughtful and important. However, the efforts currently being considered also highlight a gap in the existing system in the west. In order to require that participants come to the market "Firm for the hour", an analysis of the error frequency distribution associated with a Balancing Authority is being done to evaluate error across the next operating hour, using a persistence forecast from 30 minutes prior to the hour. Required reserve capacity will be determined based on a selected probability of events which would exceed that capacity. This work is ongoing, so it is not clear what the final parameters will be, but a probability of 95% has been examined. This analysis will be done on a Balancing Authority level (as opposed to a system-side/reserve sharing group level), and the result of this calculation will be the required reserve capacity needed to allow participation in the EIM. For smaller Balancing Authorities such as ours, this is a catch-22. To integrate our wind with the system, we want (and should want) to participate in the EIM. However, due to the resource sufficiency requirement, the amount of reserves that a Balancing Authority would need to carry would remain unchanged from the current business as usual because the resource sufficiency requirements still assume the scheduling time frames currently in place, and does not allow the benefits of diversity to be included in the assessment of those requirements. For larger Balancing Authorities, this may not seem to be a problem now, because they may currently have sufficient

internal diversity and reserves in their own system to cover the current requirements. However, as load and generation variability continue to increase, thereby requiring capacity reserves to be increased under the considered EIM-related reserve requirements, this inefficiency will also impact those entities, and by extension the cost to the underlying retail consumer.

In order to demonstrate the impact of system-wide aggregation on the reliability of wind generators, the NREL western wind data set [1]from 2006 was used to generate a histogram of the forecast error associated with a regionally diverse subset of the NWPP member states included in that data set. The forecast was assumed to be 30 minute persistence, held constant for the full operating hour. The hysteresis-corrected SCORE value was used to include the impact of both loss of wind and high speed cutouts. A comparison of applying this approach to reserve requirements for both an aggregated 10,000 MW system and an individual 100 MW site are shown in Figure 1 and Figure 2 below. It can be seen that there is much more volatility relative to the installed capacity, which is a result of geographical diversity (i.e., a higher volatility is calculated the smaller the geographic footprint). Further, it can be seen in Figure 2 below that if the proposed resource sufficiency approach was applied at an aggregate system level, and reserve requirements to reach 95% reliability were allocated pro-rata, only 2% of installed capacity would be required. If the individual site level was evaluated to determine the 95% reliability requirements, then the requirements would be 8% or installed capacity, or 4 times what is needed by the system in aggregate. Also note that the NREL data set appears to underestimate the volatility in in the western region, so the actual realized requirements are higher than estimated by that approach.

The impact of calculating a resource sufficiency for an individual site as opposed to an aggregate system is shown in Figure 3 below. On that chart,

the x-axis represents the size of the project being evaluated, and the y-axis represents the resource sufficiency requirements calculated using a 95% probability. It can be seen that as the installed capacity reaches about 1,000 MW, the required reserves on a system wide level drop to 2-3% of installed capacity. In the extreme case where the reserves were calculated at the each individual site level, then the result would be 4 times higher.
Figure 3: Comparison of Reserve Requirement Calculated on Aggregate vs individual statistics

III. Recommendations

NaturEner is extremely appreciative of the work that NERC, WECC, PEAK and the NWPP are doing to improve the efficiency and reliability of the grid. Though the issues that we have raised here may have a greater impact in the near term on smaller Balancing Authorities such ours as compared to larger balancing authorities, as shown above the issues represent a detriment to all grid participants and the consumer, an unnecessary and avoidable hurdle (especially to renewable generation), and an inefficient allocation of capacity reserves and related transmission.

A. Revise the Definition of "Balancing Contingency Event" to Include Unpredicted Loss of Generation Capability.

Accordingly, NaturEner requests that NERC revise the definition of "Balancing Contingency Event" to add a clause iv. to subsection A.a. providing for unpredicted loss of generation capability, so that that subsection will then read as follows:

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System,

iii. sudden unplanned outage of transmission Facility, or

iv. unpredicted loss of generation capability

The SDT believes that the loss of predicted generation *capability* does not impact an entity's ACE. Therefore, the loss of generation capability does not require response in a similar manner to loss of generation. In a loss of renewable generation similar to your example there is no prohibition on the utilization of Contingency Reserve. A change in ACE from the loss of this renewable resource would need to be addressed by an entity experiencing a Reportable Balancing Contingency Event at the same time. As of today, no one has provided a better reserve requirement than MSSC, therefore this is the required reserve recommended in this standard.

B. Other Suggested Recommendations.

In addition to revising the definition of "Balancing Contingency Event" as suggested above, NaturEner suggests that NERC's providing of support and encouragement for the following considerations wherever appropriate would also help both alleviate the problems and advance the benefits discussed above.

1. Efforts should be made to encourage regional reserve sharing groups to allow unpredicted loss of generation capability events as qualifying

contingency events, to the extent events are not already allowed by such groups.

a. Qualifying events could be defined using a reasonable persistence probability of exceedance approach.

b. Alternately, the historical contingency events of conventional generators could be evaluated to provide a benchmark for defining the allowable frequency of allowable variable generation contingencies.
Unpredicted loss of generation *capability* does not impact ACE therefore, the SDT does not agree with your comment. The definition of a Reportable Balancing Contingency Event takes into account historical events of conventional generator. To the extent renewable generation loss meets the definition of Reportable Balancing Contingency Event the SDT does not believe there is any distinction between renewable generation and conventional generation. To the extent that the comment looks for the SDT to advocate for Reserve Sharing Groups to have specific rules, that is a commercial issue beyond the scope of NERC.

2. Requirements for resource sufficiency in energy imbalance markets should be aligned with specified qualifying contingency events in regional reserve sharing groups.

a. Doing so would encourage participation in EIMs, while centralizing the planning for contingency management.

3. Resource sufficiency should be evaluated at a system-wide level, as opposed to at the individual Balancing Authority-level.

a. Failure to do this will result in inefficient and unnecessary acquisition and deployment of capacity and related transmission.

The SDT believes that issues 2 and 3 are commercial in nature and therefore beyond the scope of this drafting team.

Devon Yates, Manager, Operational Analytics, NaturEner USA, LLC

Response:

Jared Shakespeare - Peak Reliability - 1 –

Answer Comment:

While the SDT has responded to comments on the term "sudden" by saying the word does "not need further definition as any definitive definition would be somewhat arbitrary and possibly ill-fitting for one size entity while perfectly reasonable for another," Peak continues to believe that lack of a clear definition may cause confusion, disagreement and inconsistency. Absent further clarity in the standard, Peak plans to continue to interpret "sudden loss of generation" as instantaneous or when the breaker trips. The SDT understands that different areas of the North American interconnections handle the definition of "sudden" differently to accommodate the needs of the area. The SDT felt the definition allowed for the specific areas to meet their needs within reason. Peak Reliability's interpretation works for their needs, however may not work in another area. Therefore the SDT believes that the definition satisfies the entire NERC body.

The language in R1.1 is confusing with respect to the expectations for multiple Balancing Contingency Events. Please provide an example of the required recovery magnitude and timeline of multiple Balancing Contingency Events.

	The SDT believes that an entity can utilize CR Form 1 to run different scenarios, thus providing an entity with examples of the required recovery magnitudes and timelines for multiple Balancing Contingency Events. Please provide a technical justification for the varying thresholds in the different Interconnections. It is unclear why the threshold in the Western Interconnection would be vastly lower than the threshold in ERCOT or even than the Eastern Interconnection. For example, there are 50 units with a PMAX of 500 MW or greater in the Peak RC Area. This is a significant number that will lead to more DCS events that do not significantly impact reliability but will distract from other key monitoring activities. The MW thresholds are based on a statistical evaluation of historical events in each interconnection and their impact on frequency in that interconnection. At a high level, the definition of a frequency event in each interconnection is defined by the frequency impact of an event and the interconnection characteristics. Please refer to the Background Document posted with this standard. The SDT utilized conservative numbers in order to provide the System Operators with the necessary information to operate the grid while maintaining compliance.
Response:	

Additional Comments Received from Steve Johnson – Western Area Power Administration

Thank you for the opportunity to comment on the draft BAL-002-2 standard. Western Area Power Administration would like to provide the following comments:

1. We request clarification on the "system models" information.

System models are those models that are used to plan reliable operation of the interconnection. The models would be used for near-term (next hour to next week) planning as well as longer term planning. Whether this is a single model used by an entity or multiple models used by an entity, each of them would be expected to include an evaluation of the entity's likely contingencies as required under the TPL standards.

2. We would like to request clarification on the clock-hour language that was included in the R2 rationale, but removed. The focus here is that we want to make sure the clock-hour average is still how we will be measured and not individual AGC cycle contingency reserves calculations for carrying sufficient reserves.

   Under the proposed standard, there is no real-time measurement of Contingency Reserves in R2. Instead, the requirement is for the day-ahead Operating Plan to show that there is an expectation that the Responsible Entity will have the necessary Contingency Reserves. The time frame for this plan is dependent upon the time frame used by the Responsible Entity.

3. In 1.3 its stated "deploy Contingency Reserve, within system constraints." We are not sure what is meant by "system constraints" please clarify.

   The normal constraints that are used for determining the limits of the system, including System Operating Limits, Interconnection Reliability Operating Limits and other pertinent operating limits determined by the Transmission Operator, Generator Operator, Balancing Authorities and monitored by the Reliability Coordinator(s).

Additional Comments Received from Phil Hart – Associated Electric Cooperative, Inc.

AECI appreciates the drafting team's persistent efforts to further improve BAL-002-2 through standards development. The requirements within the current revision are an improvement over the currently enforceable BAL-002-1 and previous revisions. However, after considering FERC's approval of the BAAL operating criteria (BAL-001-2 R2) in Order 810, the reliability benefit, or need, of a BAL-002 standard is no longer apparent.

The objective of the BAL-002 standard could arguably be redundant with the contingency reserves inherently required to be compliant with the BAAL operating criteria. The objective of BAL-002-2 states: "... to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event." Without proper context this objective sounds very similar to the understood objective of the BAAL operating criteria, with two distinct differences: BAL-002-2 requires an ACE value return to be performed without any consideration for interconnection health (frequency), and this recovery is required to be 15 minutes instead of 30 (which the 10 year field trial found to be a reliable time period for recovery). These differences do not mitigate any additional risks to the system, rather they create additional risks to the system.

By imposing additional requirements above and beyond BAL-001-2, the BAL-002 standard can negatively affect reliability by forcing entities to disregard the frequency of the interconnection and respond with corrective action that would push interconnection frequency further from schedule. Standards requirements should not require "backup" standards requirements, these requirements mandate to entities "how" they must comply with another standard and only create regulatory burden for entities.

Compliance with BAL-001-2 R2 inherently requires a contingency reserve policy, and will be required continent wide. The unexpected loss of generation or load is an assumed risk that is taken by Balancing Authorities while striving to meet customers energy demands. They also assume compliance risks. If an entity does not carry sufficient reserves or has measures in place to import energy (RSG, interchange transactions, etc) prior to an event occurring, AND their lack of response in a timely fashion creates a negative impact to the Bulk Electric System, they will be in violation of the BAL-001-2 standard. To mitigate this compliance risk, entities MUST carry contingency reserves. If they do not then they will eventually violate BAL-001-2 R2. If they do not violate BAL-001-2, then no real risk to reliability was imposed on the system and any requirement that determined a non-reliability related event as a violation would prove itself to be non-risk based.

The BAL-002 project has been a long one. While the project intent and associated FERC directives may have been applicable during the initial phases of development, the recent acceptance of the BAL-001-2 and BAL-003-1 standards could warrant the development of an alternate approach. For instance, a specific definition of the remaining directives and their relationships to BAL-001 and BAL-003 could prove that these directives have been met. A refocus of the team's effort now, as opposed to later, may be a better use of NERC and industry resources while also advancing the NERC initiative for Results Based Reliability Standards Development. For this reason, AECI requests that NERC and the drafting team re-evaluate the reliability risks related to this standard, along with the outstanding FERC directives, to evaluate the need for the BAL-002 standard.

Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

Additional Comments Received from the ISO Standards Review Committee

The SRC agrees with the intention of the SDT draft 7 posting to:

- Provide the risk based parameters (ACE range, Recovery period, Restoration period) for responding to a Balancing Contingency Event (BCE);
- Ensure that the definition of Most Severe Single Contingency (MSSC) does not include more than one resource;
- Ensure that the definition of BCE does recognize the possibility of the loss of more than one resource;
- Eliminate draft 6's hourly obligations; and
- Clarify that shedding load is not an expected action in order to maintain reserves.

The SRC does not agree with proposed standard wording that:

- Links MSSC to BCE; and
- Links Contingency Reserves (CR) to Disturbance Control Standard (DCS) compliance.

The SRC proposes clarifying modifications to definitions for:

- Balancing Contingency Events;
- MSSC;
- Contingency Event Recovery Period; and
- The EEA level referenced in R1.3.1

The SRC again asks the SDT to remove the language within draft 7's proposed CR requirement that ties DCS compliance to the use of CR.

For compliance with Requirement R1 Part 1.1 response is determined by your ACE within the first 15 minutes regardless of how recovery is accomplished. Requirement R1 Part 1.3 describes the process for when events combine to be greater than MSSC and provides exclusion from compliance for Part 1.1. However, exclusion from compliance for Part 1.1 does not allow an entity to avoid responding at all to a large event. Note that Part 1.3 does not require all Contingency Reserves be activated.

The SRC has characterized its comments in three classifications: those proposed to facilitate clarity; those proposed to ensure that the focus of requirements remains on reliability; and those proposed to address other concerns.

Revisions Proposed To Facilitate Clarity

The SRC would ask that the SDT to redraft the requirements in more direct terms. Phrases like "demonstrate recovery" in the requirement section of the standard can be construed ambiguously and a clear reliability requirement omits unnecessary words and directly defines the obligation.

In particular, the SRC suggests that the linkage between R 1.1 and R1.31 is a source of ambiguity within the standard because:

- Requirement R1.1 defines the target ACE correction (range of recovery);
- Requirement R1.3 defines Contingency Reserve deployment;
- Sub-Requirements of R 1.3 then introduce exceptions for **R1.1** (*i.e.*, R 1.3.1 and R 1.3.2).

This organization does not allow readers and entities responsible for compliance and direct correlation between specific defined obligations and the proposed exemptions. To facilitate clarity, the SRC offers two recommendations. The first recommendation preserves much of the current, draft language while the second recommendation provides more streamlined language:

1. *Retaining current draft language:*

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

• zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

• its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

~~**1.2.** document all Reportable Balancing Contingency Events using CR Form 1.~~

~~**1.3.** deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if: **1.3.1** the Responsible Entity is:~~

Unless:

- the responsible entity:
  - is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher; is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan; or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency .

~~or,~~

- the following subsequent event(s) occur:

~~**1.3.2** the Responsible Entity experiences:~~

  - multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Even;, or
  - multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

2. *More direct version*:

R1. Unless the Responsible Entity is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher, is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, , the Responsible Entity experiencing a *Reportable Balancing Contingency Event* (RBCE) shall return its ACE to:

- Zero within the *Contingency Event Recovery Period* if the Responsible Entity's Pre-RBCE ACE Value were positive or equal to zero; or
- Its Pre-RBCE ACE Value if the Responsible Entity's Pre-RBCE ACE Value were negative

Where a Balancing Contingency Event exceeds the responsible entity's MSSC or multiple Balancing Contingency Events occur within the Contingency Event *Restoration period* of the 1st RBCE, the responsible entity shall deploy contingency reserves, but such response shall not be subject to Requirement R1:

The drafting team appreciates the commenters effort to make the language clearer. The SDT believes that the existing format provides the clarity needed withal details. The proposed eliminations and reformatting does not accomplish the SDT's intent. The proposed EEA level is unsupportable. According to the definitions of the EEA levels, there is no acceptable reason to excuse performance for an entity in an EEA Level 1. According to the definition of the EEA Level 1, an entity should have all necessary contingency reserves. Therefore the entity should respond according to R1 and correct their ACE within the Disturbance Recovery Period.

Revisions proposed to ensure that the focus of requirements remains on reliability

The SRC asserts that the primary focus of BAL-002 should be reliability (ACE recovery) with less focus be given to the specific process regarding how to meet the reliability requirement. The current draft appears to link economic sharing arrangements (Contingency Reserves) to a reliability requirement and, therefore, precludes the use of more effective processes to meet the reliability requirement. The SRC cautions the SDT against mandating the use of a process where such usage would be inappropriate from both a reliability and cost efficiency perspective when other processes are available For example, as written, draft 7 could preclude the use of Demand Side Management (DSM) as Contingency Reserves (in contradiction of Order 1000), and restricting DSM to Emergencies only. For these reasons, the requirements should be re-focused on what needs to occur for reliability – not how such activities are performed.

The drafting team's main focus is on reliability and as drafted, states the requirement but does not define how an entity must accomplish the goal. For example, the requirements do not require the use of Contingency Reserve for a measured Reportable Contingency Reserve Event. The measurement is only based on the ACE value within 15 minutes from the time of the event. The only area where there is a required use of Contingency Reserves is for events that exceed an entity's Most Severe Single Contingency. In these cases, there should not be an expectation that a system operator need do nothing since the event is not going to be subject to mandatory compliance. Instead, the expectation should be that the operator will address the imbalance created *to a reasonable extent through the use of deliverable Contingency Reserves* without a requirement to fully restore ACE to any specific level.

The SRC does recognize the SDT's attempt to address the issue of maintaining reserves designed to preserve serving load verses the issue of shedding load to preserve reserves and that it makes no sense to shed load to maintain reserves that are designed to protect load from being shed. Additionally, the SRC questions the need for the proposed Requirement R2 (*i.e.*, the requirement to have a method to compute MSSC).

Such requirement is administrative in nature as it mandates a creation of a procedure, an implementation process for that procedure, as well as a mandate to "have" a market service to calculate MSSC. The sentence in draft 7 can be read as ether:

- an annual obligation to compute MSSC and to use that annually-computed MSSC in system operations, and
- carry an equivalent amount of reserves for that year

or

- develop a plan to explain how to compute MSSC and review that plan every year
- implement the computation (the implication is that the plan will introduce the time frame for updating MSSC)
- carry an equivalent amount of RC (for as long as the plan states)

The definition of MSSC is axiomatic and does not require a formal procedure. The only plausible justification for having such a plan is mandate self-imposed rules regarding when to compute MSSC; how to apply that calculation; and for how long. Given the ambiguity in draft 7's R2, either approach can be justified. Such ambiguity would not serve reliability. As an example, if draft 7 really did intend linking MSSC to an annual value, and in doing so lock-in a minimum reporting value (80% of MSSC), then what could occur is that small BAs can have a minimum reportable value that is larger than any unit that is operating on a given day – in effect - exempting them from ever reporting. On the other hand, if draft 7 really did intend to provide flexibility to the BAs, a number of questions arise: Is this a daily scheduling function, or a continuous operating function? Is the objective fixed or does it depend on what is operating at the given time? Accordingly, the current approach could be interpreted broadly and variably and should be revised as it does not appear to be directly focused on or facilitating reliability.

The drafting team believes that the Operating Process developed by the Responsible Entity would address these concerns related to potential ambiguity. The drafting team understands that it is possible, although somewhat unlikely for an entity to have an MSSC that does not change during the course of an operating year for several reasons. However, the drafting team does not believe that this is an issue in the standard. Rather it is an issue that entities need to address as part of the required Operating Process. As an example, an entity may determine that the largest loss it could ever expect would be 1,000 MW so that is the level they will carry at all times, regardless of their real-time number being lower on any given day. This would be a means to ensure that compliance with R1 would not be an issue, although arguably it may not be very efficient. Another entity could decide that the loading of a transmission line far exceeds the size of the largest generator so they would plan to forecast the line loading and set a floor for their Contingency Reserves equal to the size of their largest generator, thus allowing the MSSC to fluctuate each hour in their Operating Plan. However, in both cases, the real-time number will drive compliance with R1. Therefore, the drafting team believes that the proposed definitions and requirements address appropriately the possible operational practices.

Revisions Proposed to Address Other Concerns

The SRC suggests the following comments and/or revisions for the SDT's consideration:

1. Delete the phrase "within system constraints" in Requirement R1. Because BAs are not responsible for system constraints (that's the role of TOP), the inclusion of this phrase connotes that a BA can be held responsible for exacerbating a SOL problem, even if the BA had no knowledge of the limit and was taking actions to comply with its obligations. The requirements should respect current roles and responsibilities of the various functions and, currently, the TOP is responsible for directing the BA in this regard.

The drafting team agrees the BA is not responsible for determination of system constraints. However, the following selected list of Requirements from Standards, either currently enforceable or approved by the NERC Ballot Body, NERC Board of Trustees and filed at FERC requesting approval for future enforcement, makes it clear that a Balancing Authority can't perform their duties reliably without being knowledgeable of system constraints.

TOP-001-3 R20
TOP-002-2.1b R4, R5, R6, R7, R9 and R10
TOP-002-4 R4
TOP-003-1 R1.2
TOP-003-3 R2, R4 and R5

Finally, removing the phrase would make a requirement to activate all Contingency Reserves, regardless of any negative impacts to the Bulk Electric System for large events. The drafting team discussed this concern and determined that the BA should only activate the level of reserves that could be safely used without creating reliability issues on the grid.

2. The standard has a reporting requirement, but does not include a reporting timeframe. Therefore, the most conservative assumption would be that reporting is on and "individual event" basis. For draft 7, the SDT rejected quarterly reporting based on a non-relevant paragraph in Order 693.

354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters.

The SRC requests that the SDT explain its correlation between the reporting requirement and P 354 and requests that the SDT clarify the timing of any required reporting. Additionally, the SRC is unclear as to how "the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure." Upon review, it appears that values for entities are calculated on a % of recovery whether applied to an individual event or quarterly performance – accordingly the severity of a violation would still be correlated to overall performance for some time period. The SRC requests that the SDT re-evaluate its explanation and provide additional clarification.

R1 part 1.2 does not require a report to be submitted to any entity, only to "document all Reportable Balancing Contingency Events" in a manner that ensures consistency. It requires the documentation of an entity's restoration of ACE be on the referenced form to demonstrate that the entity did restore its ACE as required. This ensures all entities utilize the same methodology for each event. Refer to the measurement for R1 to see that the form is used to calculate the response, not to report anything to NERC or a Regional Entity. The drafting team did not put a requirement into the standard that an entity report a failure as this is a compliance issue and should not be part of a reliability standard.

3. The Draft 7 definitions of MSSC and BCE do not resolve the issue of BCE being greater than the MSSC because Draft 7 continues to link the definitions of MSSC and BCE. The SRC believes MSSC is an a priori / actual state value while BCE is an a posteriori event/experience. The SRC agrees with the SDT that MSSC can never be more than one resource otherwise it would not be a "single contingency." BCE on the other hand can (as the current definition indicates) include the impacts of the loss of more than one resource. To address this concern, the SRC offers the following comments and revisions.

Draft 7 definition of MSSC:

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a

Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Draft 7 definition of 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 one minute or less.

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's 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 unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Given the above definitions, the SRC concludes that the SDT correctly wants to ensure that MSSC include large interchange schedule imports as well as large generators. The definition of BCE does that (see sub item B). The draft 7 definition of MSSC relies on the definition of BCE to ensure that such interchange gets considered. The problem is that the foreword of the BCE definition includes the phrase “or any series of such otherwise single events.” That addition makes it virtually impossible to quantify / limit one single resource amount for an MSSC.

The SRC would suggest that Draft 7 definition of Event be retained, but that the definition of MSSC be redrafted. The SRC suggests:

MSSC is the MW capacity of the single largest resource scheduled to operate for a given day's peak load. The resource may be a generator (Maximum Continuous Operating Capacity) or a Firm Interchange scheduled import.

This revision:

- Changes the MSSC definition from being linked to a Balancing Contingency Event of undefined size, to linking MSSC to an easily identified single resource capacity/expectation.
- Can be used to provide clarity concerning why and how the amount of CR can be set to a daily MSSC; and how and why every CBE can be "reported" upon without being subject to the DCS objectives for an MSSC.

The definition of MSSC states "due to a single contingency" and identified in the system models. The phrase "any series of such otherwise single events" is utilized for recovery measurement, not establishment of Most Severe Single Contingency. However, in actual operation, there can be events that are nearly simultaneous. In order to clarify that these events could be considered a single Balancing Contingency Event, the definition of Balancing Contingency Event provides for this. However, the Reportable Balancing Contingency Events are limited to the size of the identified MSSC.

The Draft 7 definition CR does not define what CR is, but rather defines what CR may be used for. Moreover, the definition's use of the phrase "provision of capacity" requires further explanation to clearly delineate between the concept of "provision of capacity" in the Operating Planning environment (meaning to request that resource be made available to serve load) versus the "provision of capacity" in the compliance/operating environment (meaning the amount of energy that was produced at the request of the BA). An additional issue with the first sentence is that, as written, it specifically excludes the use of those reserves to serve firm customer load. To address this concern, the SRC offers the following comments and revisions.

Draft 7 definition of Contingency Reserves

Draft 7 definition of Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

• is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

The SRC suggests that the issue of CR and reserves in general requires an Industry-wide review; and the SDT in its introduction to its Response to Comments propose the ERO conduct such a review prior to making a decision on a final ballot. The review would be used to decide if:

- Reserves were linked to day ahead scheduling in the sense that "reserve" capacity over and above the capacity scheduled to meet a peak load. This concept was referenced in the original Policy 1 – Generation Control and Performance, (dated Feb 1, 1997) at romanette (i) If CR were viewed as scheduled available system capacity there would be no issue, because then the measurement of reserves would be focused on the planned capacity for the day. Once that capacity is synchronized it can be used for any and all purposes.

To the extent that this comment is looking for clarity of all types of reserves and how they interact, please refer to NERC's Reliability Guideline: *Operating Reserve Management*, available on NERC's website under the Operating Committee "Reliability Guidelines" link listed under the Committee Resources. The document was originally developed by the drafting team and approved by the NERC Operating Committee in 2013. A link to this page is provided below.

http://www.nerc.com/comm/OC/Pages/Reliability-Guidelines.aspx

The drafting team believes that the definition of Contingency Reserves is clear as proposed.

Supporting Diagrams Submitted by Jamie Lynn Bussin – NaturEner

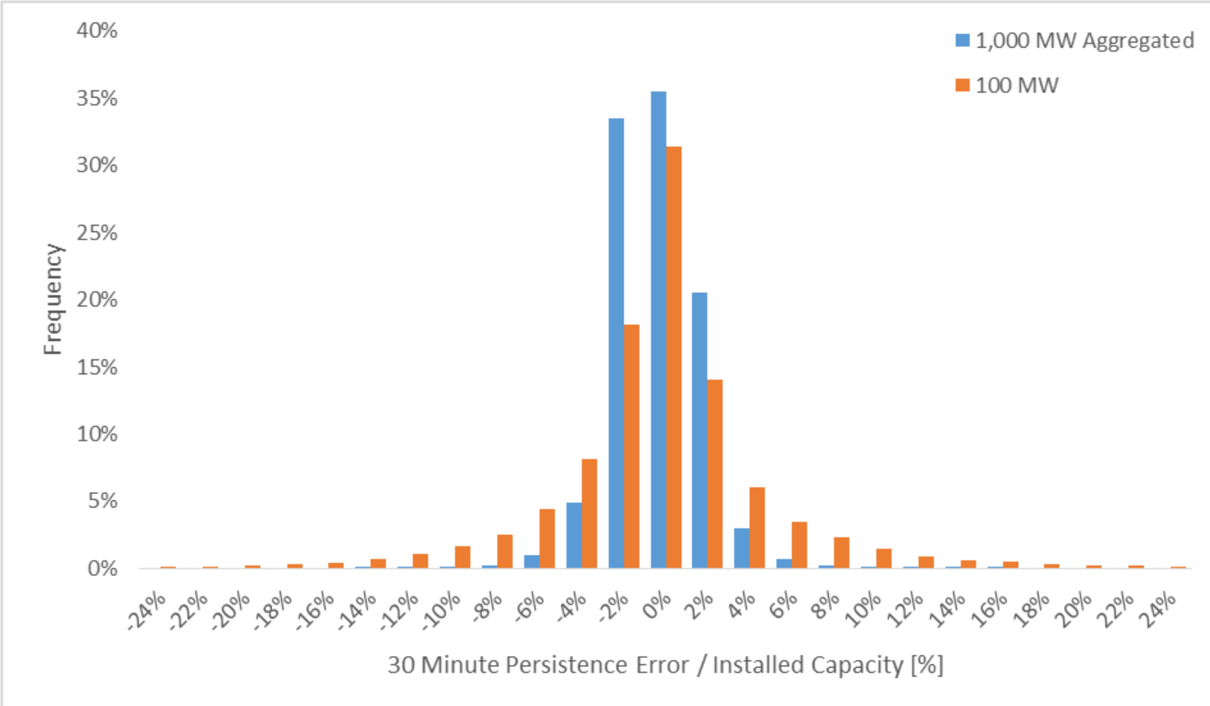

Figure 1: Histogram Comparing 30 minute ahead Persistence Forecast Error Distribution from NREL data set

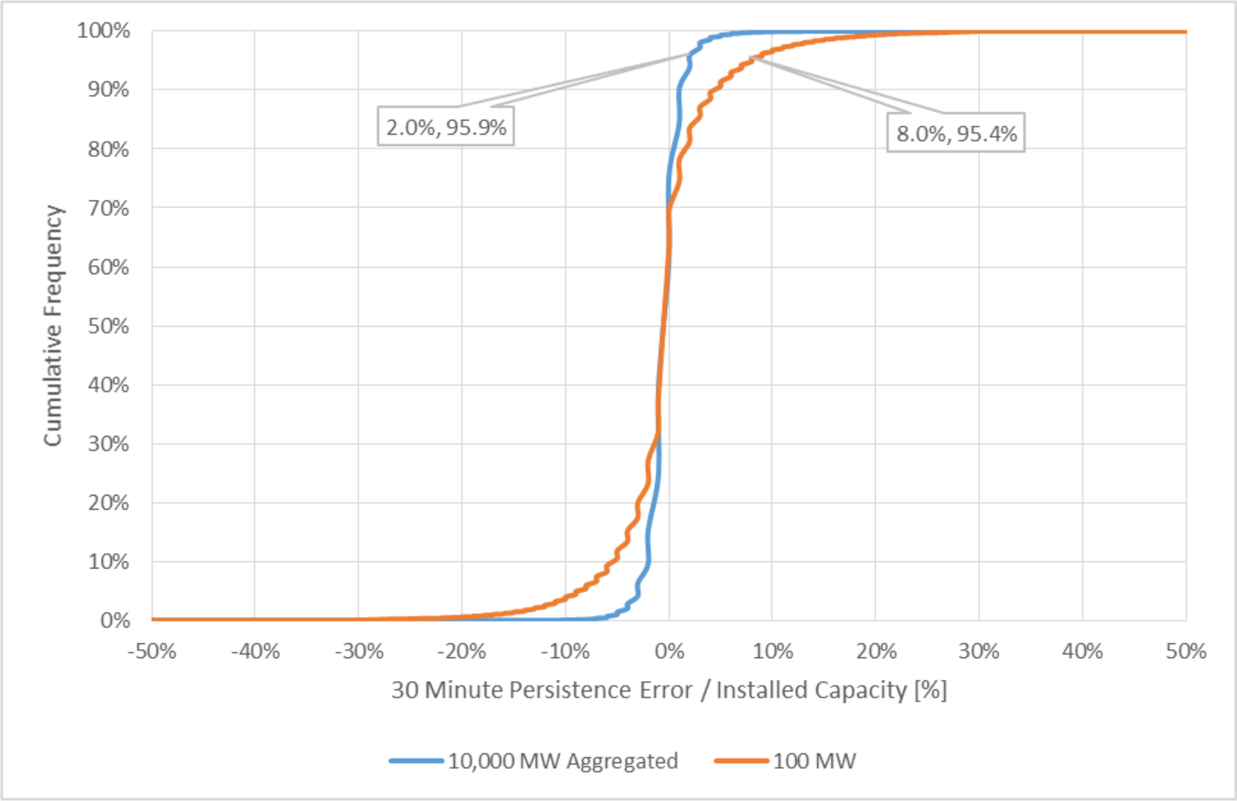

Figure 2: Cumulative Histogram Comparing 30 minute ahead Persistence Forecast Error Distribution from NREL data set

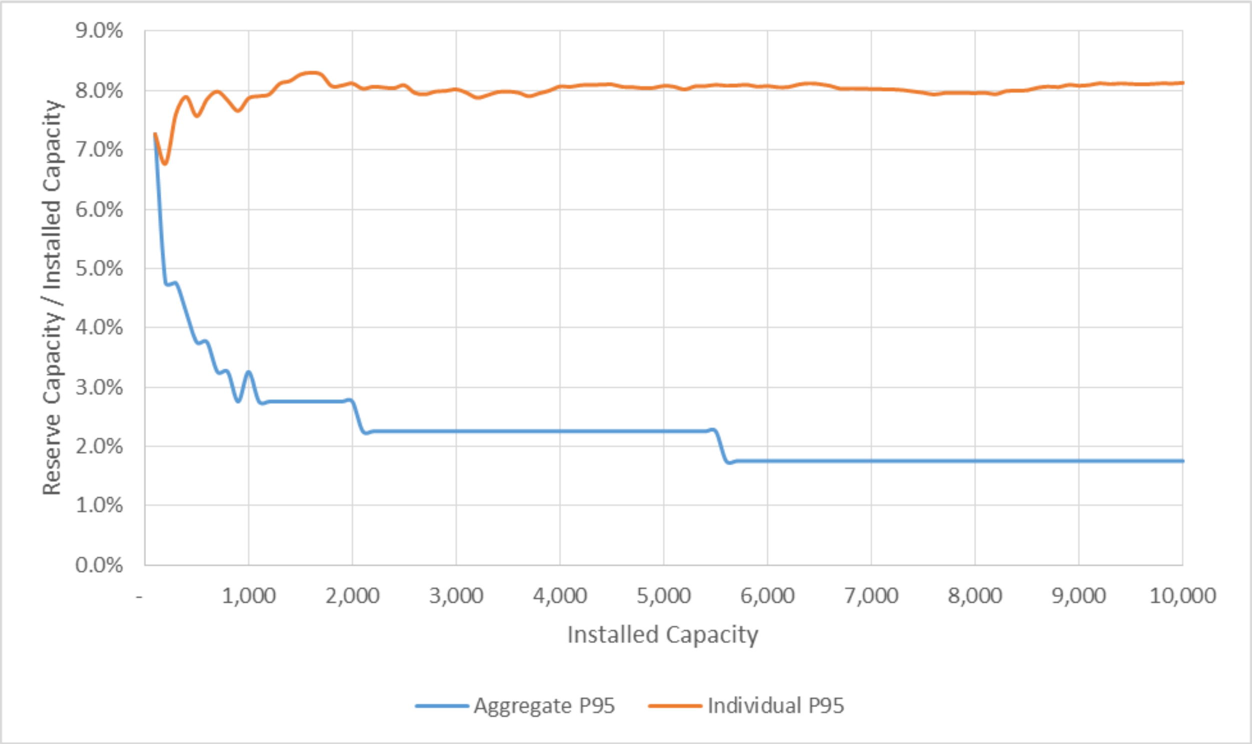

Figure 3: Comparison of Reserve Requirement Calculated on Aggregate vs individual statistics

End of Report