Consideration of Comments

Project Name:	2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls | BAL-005-1, BAL-006-2 & FAC-001-3
Comment Period Start Date:	11/10/2015
Comment Period End Date:	1/11/2016
Associated Ballots:	2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1 IN 1 ST 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-006-2 IN 1 ST 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls FAC-001-3 IN 1 ST

There were 43 responses, including comments from approximately 117 different people from approximately 84 companies representing 8 of the 10 Industry Segments as shown in the table 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. The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below. JR

2. If you are not in support of the proposed modifications to BAL-005-1, please provide your objection(s) and proposed solution(s) in the area below.

3. If you are not in support of the retirement of BAL-006-2 and the development of a guideline, please provide your objection(s) and proposed solution(s) in the area below. JR

4. If you are not in support of the proposed modifications to FAC-001-3, please provide your objection(s) and proposed solution(s) in the area below.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
PJM Interconnection, L.L.C.	Albert DiCaprio	2	RFC	ISO Standards Review Committee	Charles Yeung	PJM Interconnection, L.L.C.	2	SPP
					Ben Li	PJM Interconnection, L.L.C.	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RFC
					Kathleen Goodman	PJM Interconnection, L.L.C.	2	NPCC
					Greg Campoli	PJM Interconnection, L.L.C.	2	NPCC
					Ali Miremadi	PJM Interconnection, L.L.C.	2	WECC
					Terry Bilke	PJM Interconnection, L.L.C.	2	RFC
					Liz Axson	PJM Interconnection, L.L.C.	2	TRE

ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	ACES Power Marketing	1	RFC
					Ginger Mercier	ACES Power Marketing	1,3	SERC
					Ellen Watkins	ACES Power Marketing	1	SPP
					Michael Brytowski	ACES Power Marketing	1,3,5,6	MRO
					John Shaver	ACES Power Marketing	4,5	WECC
					John Shaver	ACES Power Marketing	1	WECC
					Shari Heino	ACES Power Marketing	1,5	TRE
					Kevin Lyons	ACES Power Marketing	1	MRO
Exelon	Chris Scanlon	1		Exelon Utilities	Chris Scanlon	Exelon	1	RFC
					John Bee	Exelon	3	RFC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RFC,SERC	Duke Energy	Doug Hils	Duke Energy	1	RFC
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RFC
Lower Colorado River Authority	Dixie Wells	5		LCRA Compliance	Michael Shaw	Lower Colorado River Authority	6	TRE
					Teresa Cantwell	Lower Colorado River Authority	1	TRE
					Dixie Wells	Lower Colorado River Authority	5	TRE

MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	MRO	3,4,5,6	MRO
					Chuck Lawrence	MRO	1	MRO
					Chuck Wicklund	MRO	1,3,5	MRO
					Dave Rudolph	MRO	1,3,5,6	MRO
					Kayleigh Wilkerson	MRO	1,3,5,6	MRO
					Jodi Jenson	MRO	1,6	MRO
					Larry Heckert	MRO	4	MRO
					Mahmood Safi	MRO	1,3,5,6	MRO
					Shannon Weaver	MRO	2	MRO
					Mike Brytowski	MRO	1,3,5,6	MRO
					Brad Perrett	MRO	1,5	MRO
					Scott Nickels	MRO	4	MRO
					Terry Harbour	MRO	1,3,5,6	MRO
					Tom Breene	MRO	3,4,5,6	MRO
					Tony Eddleman	MRO	1,3,5	MRO
					Amy Casucelli	MRO	1,3,5,6	MRO
Kelly Dash	Kelly Dash		NPCC	Con Edison	Kelly Dash	Kelly Dash	1,3,5,6	NPCC
					Edward Bedder	Kelly Dash	NA - Not Applicable	NPCC
Dominion - Dominion Resources, Inc.	Louis Slade	6		Dominion	Randi Heise	Dominion - Dominion Resources, Inc.	5,6	NPCC

					Connie Lowe	Dominion - Dominion Resources, Inc.	1,3,5,6	SERC
					Louis Slade	Dominion - Dominion Resources, Inc.	5,6	RFC
					Chip Humphrey	Dominion - Dominion Resources, Inc.	5	SERC
					Nancy Ashberry	Dominion - Dominion Resources, Inc.	5	RFC
					Larry Nash	Dominion - Dominion Resources, Inc.	1,3	SERC
					Candace L Marshall	Dominion - Dominion Resources, Inc.	1,3	SERC
					Larry W Bateman	Dominion - Dominion Resources, Inc.	1,3	SERC
					Jeffrey N Bailey	Dominion - Dominion Resources, Inc.	5	SERC
					Russell Deane	Dominion - Dominion Resources, Inc.	5	NPCC
Southern Company - Southern	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company - Southern	1	SERC

Company Services, Inc.						Company Services, Inc.		
					John Ciza	Southern Company - Southern Company Services, Inc.	6	SERC
					R Scott Moore	Southern Company - Southern Company Services, Inc.	3	SERC
					William Shultz	Southern Company - Southern Company Services, Inc.	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no UI O&R	Paul Malozewski	Northeast Power Coordinating Council	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Brian Shanahan	Northeast Power Coordinating Council	1	NPCC
					Rob Vance	Northeast Power	1	NPCC

						Coordinating Council		
					Mark J. Kenny	Northeast Power Coordinating Council	1	NPCC
					Gregory A. Campoli	Northeast Power Coordinating Council	2	NPCC
					Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
					Wayne Sipperly	Northeast Power Coordinating Council	4	NPCC
					David Ramkalawan	Northeast Power Coordinating Council	4	NPCC
					Glen Smith	Northeast Power Coordinating Council	4	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC

					Brian Robinson	Northeast Power Coordinating Council	5	NPCC
					Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
					Alan Adamson	Northeast Power Coordinating Council	7	NPCC
					Kathleen M. Goodman	Northeast Power Coordinating Council	2	NPCC
					Helen Lainis	Northeast Power Coordinating Council	2	NPCC
					Michael Jones	Northeast Power Coordinating Council	3	NPCC
					Silvia Parada Mitchell	Northeast Power Coordinating Council	4	NPCC
					Connie Lowe	Northeast Power	4	NPCC

						Coordinating Council		
					Michael Forte	Northeast Power Coordinating Council	1	NPCC
					Sylvain Clermont	Northeast Power Coordinating Council	1	NPCC
					Si Truc Phan	Northeast Power Coordinating Council	2	NPCC
					Kelly Silver	Northeast Power Coordinating Council	3	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jim Nail	Southwest Power Pool, Inc. (RTO)	3,5	SPP

					Mike Kidwell	Southwest Power Pool, Inc. (RTO)	1,3,5	SPP
					Kevin Giles	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP

1. The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Modifying the definition of Balancing Authority would misalign the term with the definition found in the NERC Rules of Procedure. SRP recommends retaining the current definition of Balancing Authority.

The proposed definition of AGC combines defined terms to create the phrase “Balancing Authority Area Demand” ERC recommends rephrasing the definition to avoid using one defined term to modify another. An alternative might be “Demand within a Balancing Authority Area”.

Primary Inadvertent Interchange is not a NERC defined term. It is a defined WECC term, SRP recommends adding Primary Inadvertent Interchange to the terms used continent wide. as the revised ATEC definition will be effective continent wide.

SRP recommends removing or defining terms capitalized but not defined in the NERC Glossary of Terms such as Control Area and Balancing Area. Capitalizing terms that are not defined creates confusion even when used in the rationale areas.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team will work with NERC staff to request a change to the NERC Rules of Procedure to align the definitions.

Thank you for your comment. As written, the standard uses “Balancing Authority Area” and “Demand” as two separate defined terms. The SDT does not intend for the terms to be combined into one term.

Thank you for your comment, Primary Inadvertent Interchange is defined in the proposed continent wide term “ATEC.”

Thank you for your comment. The drafting team will review the standard and eliminate any capitalized term not defined.

Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	

The definition of AGC is fine, but in the process of combining the need for common sources regarding MW and MWh values into the proposed R7, the association between AGC, ACE, MW, and MWh quantities is less clear. The user now has to combine the definitions for AGC, Reporting ACE, and R7 to get an equivalent picture compared to the original requirement. Maybe some references or revised wording in R7 would help clarify the expectations.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The drafting team is developing a guideline which should clarify expectations for Functional Entities.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy suggests a modification to the proposed definition of Automatic Generation Control (AGC), which we feel would enhance clarity and maintains the assumed intent of the drafting team. We recommend the following:

Automatic Generation Control (AGC): A process designed and used to automatically adjust a Balancing Authority Area’s Demand and resources to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

We feel that the above definition adds clarity, and with the addition of the term automatically in the definition, more adequately describes the function that AGC provides.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team agrees with your clarification and has updated the definition accordingly. This revision is not a substantive change, as the SDT has always intended for AGC to "automatically" adjust a Balancing Authority Area's Demand and resources to maintain Reporting ACE. This intent is reflected in the Rationale for AGC.	

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
HQT believes that Requirement 7 should apply specifically to tie lines, pseudo-ties and dynamic schedules that included in the ACE equation. Even though having the same scan-rate measure and having a time synchronized common source is a good practice, Tie-lines that are not included in the ACE equation that are not equipped with such will not affect adversely the control of a balancing authority. HQT proposes to modify R7 as below: 7. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority **that is included in the ACE equation** is equipped with: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and, 7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The drafting team believes the requirement as drafted assures reliable operation at all times and does not leave any doubt in the handling of information.	

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

These comments are submitted on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") LG&E/KU are registered in the SERC region for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below.

Yes

No X

Comments: LG&E/KU recommend the AGC definition be modified to add flexibility as follows:

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Area's Demand, Interchange, or resources, as applicable, to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

"Demand" is defined in the NERC Glossary as the rate at which energy is used by the customer. As written, the AGC definition could be interpreted to mean a BA is required to utilize Demand controls to adjust ACE. A BA should not be expected to use Demand controls to adjust ACE because the real-time nature of ACE and some current forms of Demand controls are not necessarily compatible. Additionally, the SDT's proposed definition does not mention Interchange which is a component of ACE and can be used to adjust ACE. Because Interchange has not typically been understood to be included in the term "resources," LG&E/KU recommend "Interchange" be expressly included in the definition of AGC. If the SDT does not accept the above recommendation, should it be the industry's understanding that the term "resources" includes Interchange?

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the clarification change to the definition. There was never any intent in the original definition that AGC was inclusive of Demand and resources. Also, Interchange is included in the defined term "Reporting ACE."

Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer	No
Document Name	

Comment

Texas RE recommends that the SDT consider the impact of changing the definition of Automatic Generation Control (AGC) on other NERC Glossary definitions prior to implementing such a change in this project. Although the SDT's stated goal of converting the AGC definition from a prescriptive "how to" requirement to an arguably more flexible, performance-based approach is laudable, Texas RE notes that AGC is used in other NERC Glossary definitions and, as currently defined, represents a commonly understood term in the industry. For example, the term AGC is used in the following defined terms: Anti-Aliasing Filter, Overlap Regulation Service, and proposed Remedial Action Scheme. Accordingly, modifying the AGC definition in one context without considering the consequences of such a change for other defined terms could introduce unnecessary uncertainty and confusion, as well as lead to unintended consequences. In light of the interlocking usage of AGC, Texas RE recommends that the SDT either retain the existing AGC definition or, at a minimum, consider the impact of changing the AGC definition as part of this project prior to making any changes.

If the SDT does move forward with the proposed changes to the AGC definition, Texas RE recommends revising the proposed definition slightly to correct what appears to be a typographical error. Specifically, Texas RE believes the phrase "that of" should be struck so that the proposed AGC definition reads: "A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE *in a* Balancing Authority Area within the bounds required by applicable NERC Reliability Standards."

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has made minor conforming modifications to the definition.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	No
Document Name	
Comment	
BPA disagrees with the modified definition of AGC; AGC is equipment or a system, not a process. Also, BPA suggests that the clause "...in that of a BAA..." could be simplified to "in a BAA." Regarding the modified definition of Pseudo-Tie, BPA requests clarification of what constitutes an "alternate control process."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has made minor modifications to the definition. Regarding your question about "alternate control process", an alternate control process could mean manual control.	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern suggests the below change to the definition of AGC: A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made minor conforming modifications to the definition.	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R	
Answer	Yes
Document Name	
Comment	
The phrase "..help maintain the Reporting ACE in that of a Balancing Authority Area …" in the revised definition reads a bit awkward. We interpret the definition is meant to be: "A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority within the bounds required by applicable NERC Reliability Standards." Please check and revise as appropriate.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has made minor conforming modifications to the definition.	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We would suggest to the drafting team to develop a rationale box for the modification of the Pseudo Tie definition as they did for the AGC definition. We feel this would help provide clarity on why the drafting team made the modifications to this term's definition and how this change will have an impact on the reliability of the BES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the SDT does not believe a rationale box is necessary for the Pseudo Tie Definition.	

John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dixie Wells - Lower Colorado River Authority - 5, Group Name LCRA Compliance	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

The phrase "..help maintain the Reporting ACE in that of a Balancing Authority Area …" in the revised definition reads a bit awkward. We interpret the definition is meant to be: **"A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority within the bounds required by applicable NERC Reliability Standards."** **Please check and revise as appropriate.**

Likes 0	
Dislikes 0	

Response
Thank you for your recommendation. The SDT has made minor conforming modifications to the definition.

2. If you are not in support of the proposed modifications to BAL-005-1, please provide your objection(s) and proposed solution(s) in the area below.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	

Comment

R1: BPA requests definition of "design scan rate" as identified in the R1. Scan rate is not a defined term in the NERC Glossary. It is unclear to what the SDT means by design scan rate and why the word "design" was added in this second draft.

R6: BPA still has concerns as to how R6 would be met. This requirement seems subjective and open-ended; it would be difficult for an auditor to apply a consistent metric or method to validate compliance. BPA proposes the following: "Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to ensure the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. The process must accomplish the following:
a. Compare MWh values from common source meters to integrated scan rate values
b. Xxx
c. Xxx

In **R7.1** BPA requests "information....for the scan rate values used in the calculation of Reporting ACE" be defined. BPA is unsure how to address the dynamic schedule portion of this requirement.

In **R7.2**, many dynamic schedules do not have MWH meters; the MWH value is simply the integrated scan rate data for the dynamic schedule. BPA proposes 7.2 be modified to read:
7.2 for all Tie-Lines and metered Psuedo-Ties and metered Dynamic Schedules, a time-synchronized common source to determine hourly megawatt-hour values agreed upon to aid in the identification and mitigation of errors.

Likes 0	
Dislikes 0	

Response

R1: Thank you for your comment. The word "design" was added to the term scan rate to assure that when a BA's EMS missed an occasional scan of data that the BA would not be held to be non-compliant with the requirement.

R6. Thank you for your comment. An Operating Process that would meet the intent of R6. is described in Section VIII. - Special Conditions and Calculations under the Title I_{ME} (Interchange Meter Error). The SDT decided the requirement should not define the specific process because it may vary from BA to BA. Therefore, the process is defined in general terms rather than specifically. **R7.1 & 7.2** Thank you for your comment. The STD intentionally left the word "meter" out of the requirement to allow BA's to use other common sources of data to support the correct calculation of ACE. The important part of the requirement is not where that data comes from. The important part of the requirement is that each BA use scan rate data based on the same source having the same value. This source could be a calculated schedule, a fixed value, or a common metering point. An integrated value is also acceptable for the synchronized value as long as it is integrated from the same source so that errors can be identified when they occur.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	

(1) We continue to have concerns with Requirement R4 and the approach taken in the wording of this requirement. We agree with the SDT that bad data quality will lead to an inaccurate ACE calculation. However, we feel the SDT should move away from concerns over data quality and instead focus on Reporting ACE calculation capabilities, as it is used by System Operators as a primary metric in making critical operating decisions.

(2) The term "operator" in Requirement R4 is too broad and the SDT should replace it with "System Operator." When we previously identified this as a concern, the SDT's response was that "By using the term operator, the BA will assure the information is provided to the correct personnel." Balancing Authorities are already required to identify such personnel as System Operators in PER-003-1 R3. The SDT should use the System Operator glossary term to align with other reliability requirements and to avoid confusion.

(3) We suggest that Requirement R5 be removed because there is an equally efficient and suitable manner of achieving the reliability result through the NERC Event Analysis (EA) Process. The EA Process, category 1h, requires entities to report when there is a loss of monitoring or control at a Control Center, and could include Reporting ACE calculation capabilities. Hence, this requirement would then be unnecessary.

(4) The SDT assumes that all tie lines between Balancing Authorities use time-synchronized meters. This may not always be true. We recommend the removal of the term "time synchronized" in Requirement R7, Part 7.2 and allow Balancing Authorities to continue to

operate to a common source when conducting their end-of-hour checks with their Adjacent Balancing Authorities. We also recommend the expansion of the VSLs for Requirement R7 where failure to meet one part would be High, and failure to meet both would be Severe.

Likes 0	
Dislikes 0	

Response

(1) Thank you for your comment. The SDT is unclear with respect to your suggested change.

(2) Thank you for your comment. The SDT believes the term operator is appropriate to reflect the differences within BAs. In the context used the term operator only applies to the BA operator, while the term System Operator includes the Transmission Operator, Generation Operator and Reliability Coordinator.

(3) Thank you for your comment. The NERC Event Analysis Process (EA) only requires reporting of a loss of monitoring or control, it does not include any requirement with respect to how often or how long a loss of monitoring or control is acceptable for reliability.

(4) Thank you for your comment. If the meters used for determining MWh values are not time synchronized, then the Operating Process required in R6 would not be valid. Time synchronization is intended to include all forms, such as accumulator freeze pulses, and not to require a specific time synchronizing mechanism. The SDT believes that Requirement R7, as written, is binary in nature. If a requirement is binary then it can only have one VSL, Severe.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

We have a concern pertaining to Requirement R3 parts 3.1 and 3.2. Our group would suggest that the drafting team provide clarity on what are the intents for this particular Requirement and its parts. At this particular time, we are interpreting that the frequency source has to be within 1mHz accuracy for 99.95% of the year.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees with your interpretation of the requirement.

Joel Wise - Tennessee Valley Authority - 1,3,5,6 -– SERC	
Answer	
Document Name	
Comment	
In R6 the SDT is using a new term called "scan rate data" which is not a defined term. This term is rather ambiguous. The phrase "affecting the accuracy of data" is clear enough. Or possibly say the accuracy of data used in calculating ACE. In 7.1 the SDT uses a term called "scan rate values". The scan rate is how fast we collect the data, it is not the type of data used here. All SCADA data has a scan rate, this could really be referring to almost anything.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the use of the term "scan-rate data" is more specific than the term "data" and applies to the specific Operating Process required in R6.	

Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	
Document Name	
Comment	
Requirement R1: Scan Rate In reading Requirement R1 and M1, it is unclear whether or not there is a requirement to utilize a scan rate. R1 indicates "The Balancing Authority shall use a design scan rate…" This almost looks like it should read "The Balancing Authority shall use a scan rate" OR "The Balancing Authority shall design a scan rate". Texas RE recommends there be a requirement to both design and utilize a scan rate as it increases the integrity of data during events as indicated by the rationale.	

Requirement R4: System Operator

As previously submitted for the initial ballot, Texas RE recommends the SDT use the term “System Operator” in R4. The rational states “System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculations are incorrect, the operator should be made aware through visual display. When an operator questions the validity of the data, actions are delayed and the probability of adverse events occurring can increase.” The definition of System Operator is “An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.” The response provide by the SDT to this issue was “The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel.” A System Operator needs to be aware of any data issues to make the correct decisions. A BA can provide the information to any other personnel it so desires but the System Operator must, at a minimum, have access to the Reporting ACE information. As written, and interpreted by the SDT, there could be possible gaps in providing the individuals whose responsibility it is to monitor and control that electric system in real time correct information. There may not be consistency within Balancing Authorities as to who the “operator” is in this requirement. Texas RE suggests the verbiage “System Operator and other personnel (as determined by the BA)” to provide clarity. As is, if a System Operator does not have the information the Balancing Authority will be compliant but may hinder reliability by delaying actions and increasing the probability of adverse events occurring. The non-definitive term “operator” will inherently inject non-uniformity in determining compliance. Each entity will have a different interpretation of what “operator” means which will appear as an inconsistency in the Regional Entity review. If an “operator” who is not a System Operator is making and acting on decisions that control the electric system in real time, is that not a concern of the SDT?

Requirement R6: Singe Balancing Authority Interconnection

Texas RE noticed R6 does not address a single Balancing Authority Interconnection. Texas RE recommends there be a requirement for an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in calculating Reporting ACE even in single Balancing Authority Interconnections.

Reporting ACE

Texas RE recommends the standard language explicitly state how DC ties should be handled rather than indicating an exclusion. In the SDT’s comment responses for Texas RE’s comments on the initial ballot, the SDT states “In the definition of Reporting ACE asynchronous DC ties between Interconnections are excluded from Reporting ACE and are handled as either a generator or load” and “Reporting ACE has been redefined to require that all DC asynchronous tie lines with other interconnections be represented as Source-Sink pairs and excluded from Reporting ACE“ yet there is no written requirement for the DC ties to be handled in any way.

Calendar Year

Texas RE recommends changing the verbiage from "each calendar year" to "each rolling 12 month period". Specifically, R3 and R5 include the term "calendar year" which implies Jan 1 to Dec 31. Therefore, if a CEA evaluates compliance to the Requirement in mid-year, there cannot be an assertion of compliance for the current year. Consequently, if the CEA returns in two years, the half year's period of data should be available to ascertain compliance (per the Evidence Retention statements) but the BA may not provide the data based on the RoP Appendix 4C Section 3.1.4.2). Texas RE considers this as a gap in compliance monitoring (and reflect a possible gap in reliability). The SDT assertion that "Since an Audit Period will include at least one entire calendar year" is incorrect. A BA has to be audited AT LEAST once every three years but may be audited more often as needed. As written the BA is non-compliant, per the VSLs, until a calendar year is complete.

Implementation Plan

The BAL-005-1 Implementation Plan lacks clarity on effective dates for the Standards and definitions in question. BAL-001-2 is effective July 1, 2016. There may not be an approval on definitions contained within BAL-005-1 (effectively BAL-005-1 itself unless the SDT has some other unapproved process in mind) before that time period. Additionally the SDT is unclear if the definitions would apply to BAL-005-0.2b, which could still be in effect after BAL-001-2 is in effect but before BAL-005-1 becomes effective. A CEA will have to evaluate the Standards and definitions that are FERC approved, not proposed, for compliance monitoring efforts.

VSL Language

Texas RE notes that some of the proposed changes to the Standard language have not been flowed through to all proposed VSLs. Texas RE recommends that the SDT review this language and ensure that the final Standard language is accurately reflected in the corresponding VSLs. For example, in the VSLs for R2 there were only corrections in the Lower VSL language to capture changes in the Standard. The changes should be reflected in the other VSLs associated with R2.

The VSL for R4 should reflect System Operators.

Likes 0	
Dislikes 0	

Response

R1: Thank you for your comment. The word "design" was added to the term "scan rate" to assure that when a BA's EMS missed an occasional scan of data that the BA would not be held to be non-compliant with the requirement.

R4: Thank you for your comment. If the term is changed as you suggest, it would require the BA to make ACE available to all System Operators (Generation, Transmission, and Reliability Coordinators) within their BA. This goes far beyond the intent of the requirement.

R6: Thank you for your comment. The SDT determined that there is only one scan-rate value, for the Actual Frequency, used in calculating the ACE for a single BA interconnection. The accuracy of Actual Frequency is covered in R3, and therefore, does not need to be included in this requirement.

Reporting ACE: Thank you for your comment. The SDT does not agree that a requirement for modeling asynchronous DC Tie Lines with another Interconnection as source sink pairs should be required for reliability purposes. When managed as a source sink pair, the DC Tie Line would have the same effect as any other load or generation, which is not required to be monitored in any specific standard.

Calendar Year: Thank you for your comment. The SDT has considered your comment at length. However, we believe such an interpretation is too strict and would lead to multiple issues throughout Reliability Standards referring to any time duration.

Implementation Plan: Thank you for your comment. The SDT intends to file the proposed modifications prior to July 1, 2016 in compliance with the FERC directive. In addition, the proposed modification to the Reporting ACE definition incorporating thee ATEC term has no impact on reliability since the WECC Regional Standard includes the ATEC definition.

VSL Language: Thank you for your comment. The SDT has reviewed the language for Requirement R2 and made the appropriate changes. The SDT has not modified the language to state System Operator instead of operator, therefore the VSL should not include the term System Operator.

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

LG&E/KU have recommended a change to the proposed AGC definition and provided an explanation in the “comments” section for question 1. Other comments regarding BAL-005-1 follow.

Requirement 3:

Frequency is a very important reliability parameter that should be monitored by the Balancing Authority. Currently, BAL-005.02b R8.1 requires that frequency metering be available 99.95% of the time. However, R3 of proposed BAL-005-2 requires frequency metering to be available 99.95% of the time “for the calculation of Reporting ACE.” This added wording appears to create a possible overlap compliance concern with R5. All Balancing Authorities understand the importance of redundant frequency metering and are today required to maintain an availability (through automatic failover) of 99.95%. However, per the latest proposed BAL-005-2 standard not only does frequency need to be available as a reliability parameter but it must be available “for the calculation of Reporting ACE.” If the “system used to calculate Reporting ACE” (addressed in R5) is unavailable then a Balancing Authority could be found non-compliant with both R3 and R5 despite having maintained frequency monitoring availability for any purpose at or above 99.95%. When compared to today’s requirement to maintain a frequency monitoring availability of 99.95%, adding “for the calculation of Reporting ACE” provides no reliability benefit given that the availability of the “system used to calculate Reporting ACE” is required to be 99.5%. LG&E/KU recommends removing the language “for the calculation of Reporting ACE” from R3 as this added language provides no additional reliability benefit. BAL-005-2 R4 and R6 appear to be duplicative with R2 in the draft version of TOP-010-1. Reporting ACE and the inputs to it are obviously Real-time data necessary to perform Real-time monitoring of the BES. LG&E/KU recommend that R4 and R6 be removed from the BAL-005-2 standard and allow TOP-010-1 R2 to be the single Balancing Authority requirement addressing implementation of an Operating Process or Procedure for Real-time data (which includes Reporting ACE and the scan rate data used to calculate Reporting ACE) quality issues. The VRF for R5 is listed as “Medium.” This appears to be an administrative function to calculate an entities prior year performance and should be assigned a VRF of “Lower.”	
Likes 0	
Dislikes 0	
Response	
R3: Thank you for your comment. The SDT does not agree that being available for the calculation of Reporting ACE is the same as requiring Reporting ACE to be calculated. The SDT does not agree that R5 and R3 are linked in any way. Your interpretation would require the system used to calculate Reporting ACE to be available 99.95% of the time instead of the 99.5% defined in R5. **R4 & R6:** Thank you for your comment. BAL-005-1 appears to be on a faster timeline than TOP-010-1. If your suggestion is implemented and BAL-005-2 is approved sooner than TOP-010-1, then there will be an interval without any requirement for an operating process or data quality indication in the NERC standards. This situation would not be acceptable. The SDT defers to NERC staff for coordination associated with the implementation timing of these standards.	

VFR for R5: Thank you for your comment. The SDT does not agree with your assessment. Reporting ACE is necessary to ensure reliability and should be calculated continuously and therefore should have a VRF of Medium.

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	
Document Name	

Comment

Tacoma Power assumes that the intent of Requriement R3, Part 3.1, is that the total complement of frequency metering equipment meets the availability specification. For example, if one frequency metering equipment has an availability of 99.94%, but there is another frequency metering equipment available as a fail-over source such that availability of the redundant sources together is equal to or higher than 99.95%, this should be considered compliant. Is this assumption reasonable?

Could the drafting team please clarify how compliance with Requirement R3, Part 3.2, would be addressed if a Balancing Authority periodically tests frequency metering equipment (e.g., annually) and finds that the equipment has fallen out of calibration since the last test? For example, in the case of analog frequency transducers, in particular, the accuracy could stray over time. If a Balancing Authority tests its frequency metering equipment periodically and discovers that the accuracy is now less than 0.001 Hz, the Balancing Authority should not be in violation, since, in this scenario, it is not reasonable for them to have identifed the inaccuracy before the frequency metering equipment went out of calibration.

Tacoma Power assumes that the intent of Requirement R7, Parts 7.1 and 7.2, is not to address the real-time status of common sources, for either scan rate values or hourly megawatt-hour values, or for loss of time synchronization. It seems that these real-time issues would be addressed under Requirement R2, Requirement R6, and/or other requirements and would not necessarily constitute a violation of Requirement R7.

Likes 0	
Dislikes 0	

Response

R3.1: Thank you for your comment. The SDT agrees with your assessment that the 99.95% availability would be met with appropriate frequency metering redundancy.

R3.2: Thank you for your comment. The SDT agrees with your assessment of discovering that metering equipment accuracy has fallen out of adequate accuracy, assuming that the redundant frequency metering is used to replace the out of compliance metering as soon as it is discovered.

R7: Thank you for your comment. The SDT agrees with your interpretation.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R	
Answer	
Document Name	
Comment	

We continue to disagree with the majority of the requirements in the standard that stipulate the capabilities that a BA must have in order to perform its reliability tasks. In our view, these are more suited for inclusion in the Organization Certification Requirements as opposed to in Reliability Standards. The ongoing process to ensure accuracy of operating information and tools is an essential component of any operating entity which provide such services and register with NERC as the responsible entity for complying with applicable Reliability Standards. To have explicit requirements for having accuracy metering data at specific scan rate and availability (R1, R3 and R5), flagging missing or invalid data (R4), having a process in place to detect and mitigate inaccurate or missing information (R6), and using common source information between adjacent BAs (R7) are the fundamental organization requirements to enable a BA (and any operating entity) perform its reliability tasks to meet its basic obligations.

If arguments are made to have these requirements specifically stipulated, then such argument can be extended to include every data and tool that an operating entity (including RC, TOP and GOP) uses to perform all of its tasks. If that's the case, there will be no end to the scope of this extension as this may include such data as PMU data, RTU data, voltage, current, MW, Mvar, frequency, etc., and tools such as on-line contingency analysis, EMS programs, line loading estimators, load flow programs, dynamic simulation software, etc. For years, operating entities have been relying on these data and tools to perform their tasks, and there have not been any notable events that occurred due to inaccurate data or tool capability.

We therefore once again urge the drafting team to consider retiring Requirements R1, R3, R4, R5 and R7 from BAL-005, and map them into Organization Certification Requirements. While argument can be made to retain R6 as it drives the proper behavior to ensure data errors are detected and mitigated, consideration may be given to also include this in the Organization Certification Requirements.

R1 from BAL-005-0.2b should be retained in BAL-005-1 and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries." CO-1 recommend the following wording for R3: R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: 3.1 that is available a minimum of 99.95% for each calendar year 3.2 that is rated to, and has a metering accuracy with a precision to ± 0.001 Hz. 3.3 checked for accuracy once each calendar year There was concerns about what quality the ± 0.001 Hz was being applied to. In the definition of Actual Net Interchange, strike the last sentence since it is too prescriptive. We believe a BA should have the flexibility to either include or exclude the actual transfers across DC tie lines based on the modeling of the facility.	
Likes 0	
Dislikes 0	
Response	
General: Thank you for your comment. The SDT does not agree with your position that, once certified, a BA will maintain these systems without degradation since they are subject to continual modification. **R1:** Thank you for your comment. The suggested R1 would be hard to enforce because there is no requirement that a BA be informed of new or modified generation or transmission within its boundaries. This is the problem that the SDT is attempting to correct. **R3:** Thank you for your comment. The SDT is of the opinion that your suggested wording is equivalent to the requirement as written. **Actual Net Interchange:** Thank you for your comment. The SDT decided that the inclusion of asynchronous DC tie lines in ACE will result in ACE errors without offsetting benefits.	
William Temple - William Temple	
Answer	

Document Name	
Comment	

PJM proposes that BAL-005 be translated into a certification requirement for the following reasons:

REQUIREMENT 1

The new R1 is a design requirement and not something that is subject to change.

Additionally, if this standard is to remain, then the name of the standard should be changed. It is now referred to as **Balancing Authority Control,** but the requirements are for **ACE Process Design**. BA Control is addressed by BAL requirements - not by this standard.

REQUIREMENT 2

This requirement is not a reliability-based standard and is not needed. R2 addresses reporting the loss of ACE to an RC. The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can't compute its own ACE, then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue - not a reliability issue.

It is a good practice that when a BA control center is not functional that it tells the RC, but this is covered elsewhere. IRO-005-3.1a R1.6 requires the RC monitor "Current ACE for all its Balancing Authorities. "

REQUIREMENT 3

The requirement defines (frequency) equipment accuracy and availability.

Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? PJM suggests that frequency meter accuracy be included in the certification process.

Average availability (R3.1) on the other hand creates a reliability gap, and that as written does not increase reliability. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time.

If an availability requirement is needed, then we suggest tie it into the same time frame as the loss of ACE mandate.

There are two concerns with the way R3 is worded:

a. With the way R3 reads, it could be misinterpreted that the frequency metering equipment requires an accuracy of 0.001 Hz for 99.95% of the calendar year. That would mean checking (and fixing) your frequency metering device every hour to ensure you do not exceed four hours during a year with a frequency accuracy less than 0.001 Hz. This is not intent of R3 and the requirement should be rewritten. The intent is that the frequency metering equipment is *designed* to have a minimum accuracy of 0.001 Hz.

b. R3 could also be misinterpreted to mean that a BA's frequency error over an entire year must be 0.001 HZ or less.

PJM believes the requirement should be removed. However if the requirement is not removed PJM submits the following re-wording of R3 for clarity:

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE:

3.1 that is available a minimum of 99.95% for each calendar year

3.2 that is rated to, and has a metering accuracy with a precision to ± 0.001 Hz.

REQUIREMENT 6

Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for "correcting errors in the scanning process." Is it more important to have a process that can address every cause of every scanning error? Is it even possible?

On the other hand, it is possible to have a process to handle no ACE values.

Requirement R6 is confusing regarding the term "errors." Are these metering errors such as spikes? Are these Inadvertent Interchange metering errors? The requirement should provide more clarity on this.

The term "scan-rate" should be changed to "scan rate." Nowhere else in the standard or the NERC glossary is this term hyphenated.

REQUIREMENT 7

R7 is a design requirement and not something that is subject to change.

PJM notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term "time synchronized" from the requirement.

R7 requires the BAs to have a common source. This could possibly pose a conflict with CIP-005-5 R1, which could be interpreted to require a Responsible Entity to have individual access to a meter. In R7, the word Tie-Line is not defined. In the NERC Glossary it is listed as "Tie Line." In R7.2, PJM's concern here is that errors would be apparent in many more ways (and much more quickly) than by calculating hourly megawatt-hour values. This doesn't appear to be a reliability requirement.	
Likes 0	
Dislikes 0	
Response	
Standard Name: Thank you for your comment. The SDT chose the new name for the standard. This is the first suggestion that it be changed. The SDT believes the current name is more reflective of the standard. **R1:** Thank you for your comment. In the early days of EMS development, it was common practice to extend the scan rate to manage additional data or calculations. A six second design does not guarantee a six second scan rate for the life of the EMS. **R2:** Thank you for your comment. The transmission of an ACE value to the Reliability Coordinator does not guarantee that the Reliability Coordinator will be aware of the loss of the ability to calculate ACE when that occurs. This requirement assures that that information is available to the RC. **R3:** Thank you for your comment. The SDT is more concerned about the accuracy than the rating of the equipment. Rating of the equipment does not necessarily guarantee the accuracy of the equipment. **R6:** Thank you for your comment. The SDT is unclear about your observation and therefore has no suggested change. The SDT will change "scan-rate" to "scan rate". **R7:** Thank you for your comment. New tie lines and tie line metering are being added and modified on an ongoing basis. This is more than a design requirement; it requires that the metering and metering methods be maintained on an ongoing basis. As long as some BAs have time synchronized metering for accumulated MWh this requirement should remain. The requirement for a common source has not been changed from the previous version of the standard, BAL-005-0.2b R12.1. "Tie Line" is the term used within the Glossary of terms and the SDT will make the change.	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

We continue to disagree with the majority of the requirements in the standard that stipulate the capabilities that a BA must have in order to perform its reliability tasks. In our view, these are more suited for inclusion in the Organization Certification Requirements as opposed to in Reliability Standards. The ongoing process to ensure accuracy of operating information and tools is an essential component of any operating entity which provides such services and registers with NERC as the responsible entity for complying with applicable Reliability Standards. To have explicit requirements for having accuracy metering data at specific scan rate and availability (R1, R3 and R5), flagging missing or invalid data (R4), having a process in place to detect and mitigate inaccurate or missing information (R6), and using common source information between adjacent BAs (R7) are the fundamental organization requirements to enable a BA (and any operating entity) performs its reliability tasks to meet its basic obligations.

If arguments are made to have these requirements specifically stipulated, then such argument can be extended to include every data and tool that an operating entity (including RC, TOP and GOP) uses to perform all of its tasks. If that's the case, there will be no end to the scope of this extension as this may include such data as PMU data, RTU data, voltage, current, MW, Mvar, frequency, etc., and tools such as on-line contingency analysis, EMS programs, line loading estimators, load flow programs, dynamic simulation software, etc. For years, operating entities have been relying on these data and tools to perform their tasks, and there have not been any notable events that occurred due to inaccurate data or tool capability.

We therefore once again urge the drafting team to consider retiring Requirements R1, R3, R4, R5 and R7 from BAL-005, and map them into Organization Certification Requirements. While argument can be made to retain R6 as it drives the proper behavior to ensure data errors are detected and mitigated, consideration may be given to also include this in the Organization Certification Requirements.

If for any reasons Requirement R3 is retained, then we would suggest rewording it to improve clarity. As written, R3 can be interpreted as a continuous accuracy requirement of 0.001 Hz under all conditions including use of secondary or tertiary backup equipment when necessary under certain conditions. We do not believe this is the intent of the requirement so it needs to be re-worded to not imply a continuous accuracy requirement. If the intent is to use primary frequency metering equipment that has demonstrated or been tested to meet the 0.001 Hz accuracy requirement, then the requirement and/or the measure should be revised to clearly indicate this is the objective/intent.

Likes 0	

Dislikes 0	
Response	
General: Thank you for your comment. The SDT does not agree with your position that, once certified, a BA will maintain these systems without degradation since they are subject to continual modification. **R1:** Thank you for your comment. The suggested R1 would be hard to enforce because there is no requirement that a BA be informed of new or modified generation or transmission within its boundaries. This is the problem that the SDT is attempting to correct. **R3:** Thank you for your comment. The SDT is of the opinion that your suggested wording is equivalent to the requirement as written. **Actual Net Interchange:** Thank you for your comment. The SDT decided that the inclusion of asynchronous DC tie lines in ACE will result in ACE errors without offsetting benefits.	
John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	

1. Although it can be viewed as a "resource", maintaining Interchange obligations is a unique enough task for a Balancing Authority to perform, APS recommends leaving Interchange in as part of the Balancing Authority definition. "…maintains Demand and resource balance within a Balancing Authority Area, while maintaining Interchange obligations, and supports Interconnection frequency in real time."
2. The wording of R7.2 appears to be combining two requirements. The requirement to have a time-synchronized common source and to agree upon the hourly megawatt-hour values the source provides. These should be separated out as the current verbiage is unclear.

Likes 0	
Dislikes 0	

Response

1. Thank you for your comment. The SDT chose to eliminate interchange because it is included in resources.

2. Thank you for your comment. The SDT modified Requirement R7 Part 7.2 to clarify the intent. The SDT believes Requirement R7 Part 7.2 does not have two requirements. The SDT believes the requirement that you have suggested should be a separate requirement for compliance purposes would be part of the Operating Process as developed in Requirement R6. "Agreed upon" is necessary to aid in the identification of errors and assignment of the errors to the appropriate BA for mitigation as necessary under the Operating Process developed in Requirement R6.

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. – 3

Answer	
Document Name	

Comment

- The proposed version of BAL-005 is inconsistent with the recommendations of the Independent Experts Review Project and the Results-Based Reliability Standard Development Guidance.
- R1, R3, and R7 are design parameters and should be moved to a Guideline (and reviewed as part of a BA Certification). They are not performance-based, risk-based, or competency-based requirements.
- R4 seems to overlap the proposed TOP-010-1 R2 creating a potentially double-jeopardy."

Likes 0	

Dislikes 0	

Response

General: Thank you for your comment. The SDT does not agree with your position that, once certified, a BA will maintain these systems without degradation since they are subject to continual modification.

R1, R3 & R7: Thank you for your comment. The SDT does not agree with your position that, once certified, a BA will maintain these systems without degradation since they are subject to continual modification.

R4: Thank you for your comment. BAL-005-1 appears to be on a faster timeline than TOP-010-1. If your suggestion is implemented and BAL-005-2 is approved sooner than TOP-010-1, then there will be an interval without any requirement for an operating process or data quality indication in the NERC standards. This situation would not be acceptable. The SDT defers to NERC staff for coordination associated with the implementation timing of these standards.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern suggests adding the below wording to the definition of Balancing Authority:

The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, while maintaining scheduled interchange and supporting Interconnection frequency in real time.

Southern Suggests adding the below wording to R1 and M1:

R1. The Balancing Authority shall use a design scan rate not greater than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate not greater than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Likes 0	

Dislikes 0	
Response	

Balancing Authority: Thank you for your comment. The SDT is of the opinion that your suggested wording is equivalent to the requirement as written, so no change is currently necessary.

R1: Thank you for your comment. In the early days of EMS development, it was common practice to extend the scan rate to manage additional data or calculations. A six second design does not guarantee a six second scan rate for the life of the EMS.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	
Comment	

ERCOT supports the comments of the IRC SRC. The comments are provided below:

The SRC proposes that BAL-005 be translated into a certification requirement for the following reasons:

REQUIREMENT 1

The new R1 is a design requirement and not something that is subject to change

Also, if this standard is to remain then the name of the standard should be changed. It is now referred to as **Balancing Area Control** but the requirements are for **ACE Process Design**. BA Control is addressed by BAAL requirements not by this standard.

REQUIREMENT 2

This requirement is not a reliability based standard and is not needed.

R2 addresses reporting the loss of ACE to an RC.

The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can’t compute its own ACE then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue not a reliability issue. Why then should the BA be mandated to tell the RC that it can't calculate ACE?

It is a good idea that when a BA control center is not functional that it tells the RC but isn't that fact covered elsewhere, such as IRO-005-3.1a R1.6 mandating that the RC monitor "Current ACE for all its Balancing Authorities."?

REQUIREMENT 3

The requirement defines (frequency) equipment accuracy and availability.

Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? The SRC would suggest that frequency meter accuracy is better left to a certification process.

Average availability (R3.1) on the other hand creates a realibilty gap, and that as written is a make work requirement. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time!

If an availability mandate is needed, then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 4

Requirement 4 is a fill-in-the-blanks standard unless the SDT defines what constitutes "invalid data" and defines "quality" (if the BA is to flag quality then the term should be defined somewhere)

REQUIREMENT 5

Requirement 5 like Requirement 3.1 mandates an average availability. The concern that should be raised is that of mandating an average availability value. If a BA has 100% availability it can stop calculating ACE for the entire last day of the year and still be compliant! Average availability is a make work requirement. Every lost scan must be saved and summed over a year. If one were inclined to want an availability mandate then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 6

Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for "correcting errors in the scanning process" Is it more important to have a process that can address every cause of every scanning error? Is it even possible?

On the other hand, it is possible to have a process to handle no ACE values.

REQUIREMENT 7

R7 is a design requirement and not something that is subject to change.

The SRC notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term “time synchronized” from the requirement.

Likes 0	
Dislikes 0	

Response

Standard Name: Thank you for your comment. The SDT chose the new name for the standard. This is the first suggestion that it be changed.

R1: Thank you for your comment. In the early days of EMS development, it was common practice to extend the scan rate to manage additional data or calculations. A six second design does not guarantee a six second scan rate for the life of the EMS.

R2: Thank you for your comment. The transmission of an ACE value to the Reliability Coordinator does not guarantee that the Reliability Coordinator will be aware of the loss of the ability to calculate ACE when that occurs. This requirement assures that that information is available to the RC.

R3: Thank you for your comment. History has demonstrated that frequency measurement devices can and do deviate from specification and require recalibration or replacement. It would be foolish to assume that once certified they no longer need to be addressed.

R4: Thank you for your comment. Invalid data and data quality flags have been used in EMS since they were first developed. The SDT does not think these terms require definition.

R5: Thank you for your comment. Since CPS1 is based upon annual average ACE performance and is the primary measure of control compliance, it makes sense to require availability over the same or a similar time period to support that measure.

R6: Thank you for your comment. The Operating Process is not defined in the requirement. Any appropriate process that manages errors in ACE and the data to support the calculation of ACE will be acceptable. However, a process that handles every scan error may deviate from the principles of good quality control and result in detrimental tampering with the system.

R7: Thank you for your comment. New tie lines and tie line metering is being added and modified on an ongoing basis. This is more than a design requirement, it requires that the metering and metering methods be maintained on an ongoing basis. As long as some BAs have time synchronized metering for accumulated MWh this requirement should remain. The requirement for a common source has not been changed from the previous version of the standard, BAL-005-0.2b R12.1.

Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC	
Answer	
Document Name	

Comment

We suggest the Standard be completely revisited to be:

R1. Each BA shall support Interconnection frequency through monitoring Reporting ACE

R2. A Balancing Authority shall maintain adequate metering, communications, and control equipment to prevent becoming a Burden on the Interconnection or other Balancing Authority Areas.

Likes 0	
Dislikes 0	

Response

R1 &R2: Thank you for your comment. The SDT believes the suggestion would result in a standard with undefined and unauditable requirements which could negatively impact reliability.

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	
Document Name	

Comment
The SRC proposes that BAL-005 be translated into a certification requirement for the following reasons: REQUIREMENT 1 The new R1 is a design requirement and not something that is subject to change Also, if this standard is to remain then the name of the standard should be changed. It is now referred to as **Balancing Area Control** but the requirements are for **ACE Process Design**. BA Control is addressed by BAAL requirements not by this standard. REQUIREMENT 2 This requirement is not a reliability based standard and is not needed. R2 addresses reporting the loss of ACE to an RC. The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can't compute its own ACE then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue not a reliability issue. Why then should the BA be mandated to tell the RC that it can't calculate ACE? It is a good idea that when a BA control center is not functional that it tells the RC but isn't that fact covered elsewhere, such as IRO-005-3.1a R1.6 mandating that the RC monitor "Current ACE for all its Balancing Authorities."? REQUIREMENT 3 The requirement defines (frequency) equipment accuracy and availability. Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? The SRC would suggest that frequency meter accuracy is better left to a certification process. Average availability (R3.1) on the other hand creates a realibilty gap, and that as written is a make work requirement. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making

maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time!

If an availability mandate is needed, then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 4

Requirement 4 is a fill-in-the-blanks standard unless the SDT defines what constitutes "invalid data" and defines "quality" (if the BA is to flag quality then the term should be defined somewhere)

REQUIREMENT 5

Requirement 5 like Requirement 3.1 mandates an average availability. The concern that should be raised is that of mandating an average availability value. If a BA has 100% availability it can stop calculating ACE for the entire last day of the year and still be compliant! Average availability is a make work requirement. Every lost scan must be saved and summed over a year. If one were inclined to want an availability mandate then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 6

Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for "correcting errors in the scanning process" Is it more important to have a process that can address every cause of every scanning error? Is it even possible?

On the other hand, it is possible to have a process to handle no ACE values.

REQUIREMENT 7

R7 is a design requirement and not something that is subject to change.

The SRC notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term "time synchronized" from the requirement.

Likes 0	
Dislikes 0	
Response	

Standard Name: Thank you for your comment. The SDT chose the new name for the standard. This is the first suggestion that it be changed.

R1: Thank you for your comment. In the early days of EMS development, it was common practice to extend the scan rate to manage additional data or calculations. A six second design does not guarantee a six second scan rate for the life of the EMS.

R2: Thank you for your comment. The transmission of an ACE value to the Reliability Coordinator does not guarantee that the Reliability Coordinator will be aware of the loss of the ability to calculate ACE when that occurs. This requirement assures that that information is available to the RC.

R3: Thank you for your comment. History has demonstrated that frequency measurement devices can and do deviate from specification and require recalibration or replacement. It would be unwise to assume that once certified they no longer need to be addressed.

R4: Thank you for your comment. Invalid data and data quality flags have been used in EMSs since they were first developed. The SDT does not think these terms require definition.

R5: Thank you for your comment. Since CPS1 is based upon annual average ACE performance and is the primary measure of control compliance, it makes sense to require availability over the same or a similar time period to support that measure.

R6: Thank you for your comment. The Operating Process is not defined in the requirement. Any appropriate process that manages errors in ACE and the data to support the calculation of ACE will be acceptable. However, a process that handles every scan error may deviate from the principles of good quality control and result in detrimental tampering with the system.

R7: Thank you for your comment. New tie lines and tie line metering is being added and modified on an ongoing basis. This is more than a design requirement, it requires that the metering and metering methods be maintained on an ongoing basis. As long as some BAs have time synchronized metering for accumulated MWh this requirement should remain. The requirement for a common source has not been changed from the previous version of the standard, BAL-005-0.2b R12.1.

Kelly Dash - Kelly Dash, Group Name Con Edison

Answer	
Document Name	
Comment	

R1 from BAL-005-0.2b should be retained in BAL-005-1 and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

Likes 0	
Dislikes 0	

Response

R1: Thank you for your comment. The suggested R1 would be hard to enforce because there is no requirement that a BA be informed of new or modified generation or transmission within its boundaries. This is the problem that the SDT is attempting to correct.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	
Document Name	

Comment

R7.2 Not all tie lines have time-synchronized meters. The adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term "time synchronized" from the requirement.

Likes 0	
Dislikes 0	

Response

R7: Thank you for your comment. If the meters used for determining MWh values are not time synchronized, then the Operating Process required in R6 would not be valid. Time synchronization is intended to include all forms, such as accumulator freeze pulses, and not to require a specific time synchronizing mechanism. As long as some BAs have time synchronized metering for accumulated MWh this requirement should remain.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	

SRP appreciates the efforts of the SDT and provides the following comments regarding the changes to BAL-005-1:

· R3 is vague and has the potential for inconsistent implementation as worded.

It is unclear whether the 99.95% availability calculation is to be applied independently to each individual metering point, or whether it should be the average availability of all metering equipment.

· R4 – SRP recommends reducing ambiguity by adjusting the requirement to state "System Operator".

· R5 – SRP recommends providing clarification on how the 99.5% is to be calculated?

· R6 – SRP recommends rewording the standard to avoid creating the super tem "Balancing Authority Interconnection.

Likes 0	
Dislikes 0	

Response

R3: Thank you for your comment. The 99.95% only applies to the frequency metering.

R4: Thank you for your comment. If the term is changed as you suggest, it would require the BA to make ACE available to all System Operators (Generation, Transmission, and Reliability Coordinators) within their BA. This goes far beyond the intent of the requirement.

R5: Thank you for your comment. Different methods of determining the 99.5% availability may be appropriate for different EMS and different BAs.

R6: Thank you for your comment. As written the SDT is using two separate defined terms not creating a "super term".

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	
Document Name	

Comment	
Provided in ACES Comments	
Likes 0	
Dislikes 0	
Response	

3. If you are not in support of the retirement of BAL-006-2 and the development of a guideline, please provide your objection(s) and proposed solution(s) in the area below.

John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP is in support of retiring BAL-006-2	
Likes 0	
Dislikes 0	
Response	

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	

Document Name	
Comment	
The SRC supports the retirement of BAL-006-2.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the IRC SRC in supporting the retirement of BAL-006.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern supports the retirement of BAL-006-2. However, we suggest requirements be included in a commercial alternative arrangement, such as a NAESB standard, rather than a guideline that only suggests approaches and behaviors and is not binding or mandatory.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support. The drafting team considered the NAESB alternative, however, since the information process is currently under the NERC OC subcommittee RS, we felt it was more seamless to maintain it under a guideline.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy supports the retirement of BAL-006-2 in conjunction with the changes in BAL-005 as well as the development of the Guideline document as an integrated package. We feel that implementation of just one of these suggestions, without the others, would not sufficiently maintain reliability concerns with the grid.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
William Temple - William Temple	
Answer	
Document Name	
Comment	
PJM supports the retirement of BAL-006.	

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R

Answer	
Document Name	

Comment

We support the retirement of BAL-006-2.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

: LG&E/KU would like to support the retirement of BAL-006 but as of now have questions regarding the guideline and implementation plan. For example, in the transition to a guideline, must existing inadvertent balances be minimized or do existing balances simply disappear?

Likes 0	

Dislikes 0	

Response

Thank you for your support. Since the balances are more commercial and have no impact on past reliability, the drafting team feels these are financial issues that could be resolved through standard business means.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

In the BAL-005-1 Implementation Plan there is a reference to retirement of BAL-006-2 under "General Considerations" but further down there is a reference to BAL-006-2 Requirement 3 under "Retirements". Additionally, there is no reference to BAL-006-2 in the "Requested Retirement" section. Which is correct?

Additionally, the BAL-005-1 Implementation Plan lacks clarity on effective dates for the Standards and definitions in question. BAL-001-2 is effective July 1, 2016. There may not be an approval on definitions contained within BAL-005-1 before that time period. Additionally the SDT is unclear if the definitions would apply to BAL-005-0.2b, which could still be in effect after BAL-001-2 is in effect but before BAL-005-1 becomes effective. A CEA will have to evaluate the Standards and definitions that are FERC approved, not proposed, for compliance monitoring efforts.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT has made clarifying modifications to the Implementation Plan for BAL-005-1 based on the information supplied in the retirement section.

The SDT intends to file the proposed modifications prior to July 1, 2016 in compliance with the FERC directive. In addition, the proposed modification to the Reporting ACE definition incorporating thee ATEC term has no impact on reliability since the WECC Regional Standard includes the ATEC definition.

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
We agree with the SDT in proposing to retire BAL-006-2 and to develop an Inadvertent Interchange Guideline that will be approved by the NERC Operating Committee at a later date.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA agrees that BAL-006-2 is an energy accounting standard and not a Reliability Standard. However, guidelines are not enforceable. BPA agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange. BPA proposes adding inadvertent accounting via a NAESB standard or business practice since the **NAESB** WEQ Inadvertent Interchange Payback Standards **already handles certain aspects of Interchange accounting.**

Likes 0	
Dislikes 0	

Response

Thank you for your support. The drafting team considered the NAESB alternative, however, since the information process is currently under the NERC OC subcommittee RS, we felt it was more seamless to maintain it under a guideline.

4. If you are not in support of the proposed modifications to FAC-001-3, please provide your objection(s) and proposed solution(s) in the area below.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	

(1) We agree with the removal of the LSE function.

(2) However, we disagree with other proposed modifications in FAC-001-3. It was determined through the Paragraph 81 project that having Facilities within a BA's metered area boundaries are administrative and unnecessary. We suggest removing Requirement R3, part 3.3 and Requirement R4, part 4.3. These are administrative requirements that are not necessary for reliability. Furthermore, the NERC Rules of Procedure Section 501.4.4 already requires NERC to "ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority." There are equally efficient means that are already in effect; therefore, the SDT should remove these requirements, as they are unnecessary.

(3) We recommend extending the implementation plan to 36 months. The proposed 12-month implementation plan is insufficient because interconnection study requests can take as long as 18 months. These could take significant amounts of time if complex issues are encountered during negotiations of interconnection agreements.

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

The Drafting Team respectfully disagrees that having Facilities within the metered boundaries of a Balancing Authority Area is administrative in nature. Generation operating outside the boundaries of any Balancing Authority must, itself, become a Balancing Authority by definition. Otherwise, it is detrimental to the Bulk Electric System by influencing Frequency with a source unknown to the rest of the Interconnection and the Reliability Coordinator. NERC requires all Facilities within the interconnected network to be within a Balancing Authority Area when they are being placed in service. Therefore, the Transmission Operator and the Balancing Authority must be informed by the asset owner and a Standard Interconnection Agreement signed prior to any operation (commercial or otherwise).

The Implementation Plan determines when you must have these procedures in place, not how long you have to conclude your interconnection study request. The proposed changes only require the addition of procedures to confirm the entity is within the metered

boundaries of a Balancing Authority. That would have no impact on the duration of an interconnection study since the studies do not consider who the BAA is for a facility.	
Likes 0	
Dislikes 0	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	

Its not that we aren't in support of the modifications to FAC-001 however, we have a concern that the documentation mentioned in Rationale 3.3 and 4.3 (Functional Model) isn't currently up to date. We would suggest to the drafting team to verify the latest review of this documentation. Also, we would suggest the drafting team verifying that this document is properly aligned with other documentation such as: The Rules of Procedure (ROP), Glossary of Terms and The Federal Power Act for consistency and reliability of the BES. Additionally, we would like for the drafting team to review the concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA in association referenced to BAL-005-0.2b Requirement R1 parts R1.1, R1.2 and R1.3. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

There currently is a separate active NERC project to align terms in the ROP and Glossary of Terms. It is outside the purview of this team to align terms between these documents. This Drafting Team contains members from both projects in an effort to help correct any incongruence. The Drafting Team believes the Rationale boxes adequately explain that Transmission Owners are not necessarily Balancing Authorities and, therefore, these roles must be defined and fulfilled prior to operations.

You are correct that these requirements align with those from BAL-005-0.2b. These requirements were relocated from that standard as part of this project. Therefore they will not be duplicative as they are replacing them.

Although the process to confirm that all Facilities reside within the metered boundaries of a BAA will use administrative means to be accomplished and evidenced, it does not take away from the importance of confirming that such relationships exists prior to operation.

Likes 0	
Dislikes 0	

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

While TVA supports the intent of addressing the metered boundaries of the Balancing Authority Area in FAC-001-3, we believe the language of R3, part 3.3, and R4, part 4.3, needs to be improved. We recommend that wording similar to that used in the rationale statements be used in the requirement sub-parts as follows:

R3, part 3.3: Procedures for confirming that the party seeking a new or materially modified interconnection has made appropriate provisions with a Balancing Authority to operate within that Balancing Authority Area's metered boundary.

R4, part 4.3: Procedures for confirming that the party seeking a new or materially modified interconnection has made appropriate provisions with a Balancing Authority to operate within that Balancing Authority Area's metered boundary.

As currently written in Draft 2, R3, part 3.3, appears to focus on "transmission Facilities" and ignores generation Facility and end-user Facility connections. Similarly, R4, part 4.3, appears to focus on "generation Facilities" and ignores transmission Facility and end-user Facility connections.

R3.3

The drafting team has made conforming modifications to Requirement R3.3 to accurately reflect the intent of the drafting team, as described in the Rationale for R3.3. As stated in the Rationale, "it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority *to ensure its Facilities are within the BA's metered boundaries*, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation." Additionally, the "Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries." By removing the term "transmission," Requirement R3.3 more clearly reflects the fact that a Transmission Owner properly addresses procedures for confirming that those responsible for reliability of the *applicable* affected systems are within a Balancing Authority Area's metered boundaries. This change promotes reliability because it ensures confirmation that all entities that affect reliability share relevant information because they are within a Balancing Authority Area's metered boundaries.

R4.3

The drafting team has made conforming modifications to Requirement R4.3 to accurately reflect the intent of the drafting team, as described in the Rationale for R4.3. As stated in the Rationale, "it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority *to ensure its Facilities are within the BA's metered boundaries*, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation." Additionally, the "Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries." By removing the term "generation," Requirement R4.3 more clearly reflects the fact that a Generator Owner properly addresses procedures for confirming that those responsible for reliability of the *applicable* affected systems are within a Balancing Authority Area's metered boundaries. This change promotes reliability because it ensures confirmation that all entities that affect reliability share relevant information because they are within a Balancing Authority Area's metered boundaries.

Likes 0	
Dislikes 0	

Jason Snodgrass - Georgia Transmission Corporation - 1

Answer	
Document Name	

Comment

FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC-001 were removed including a requirement for metering and telecommunication.

Additionally, GTC understands that FAC-001 and FAC-002 are complimentary Standards in a sense that FAC-001 requires Transmission Owners or Generator Owners to define the interconnection requirements necessary to collect data from entities such that the Planning Coordinator and Transmission Planners can study the impact of interconnecting new or materially modified Facilities to the BES in accordance with FAC-002.

All of the requirements of FAC-001 are limited to the long-term planning time horizon. Based on the rationale and proposed language provided for R3.3 and R4.3, a new level of ambiguity has presented itself that could lead some to conclude that these interconnection requirements should be expanded beyond the planning horizon and lead up to “commissioning of a Facility” which resides in the operations horizon.

Based on the Ballot supporting material, the proposed FAC-001 R3.3 and R3.4 requirements were originally included in BAL-005-1. The goal of the requirement in BAL-005-1 was to ensure that Area Control Error is calculated properly. Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R3.3, R4.3) would violate paragraph 81 criteria and introduces ambiguity associated with the aforementioned planning horizon vs operations horizon concerns that is currently not addressed in FAC-001 or FAC-002. GTC believes this concern is already covered in operation horizon standards such as TOP-003-3. Specifically, R4 of TOP-003-3 already addresses and requires the BA to distribute its data specification to entities that have data required by the BA analysis functions and Real-time monitoring. Additionally, R5 of TOP-003-3 requires each TOP, GO, GOP, TO, LSE, and DP to satisfy the obligations of the documented specifications.

In summary, GTC believes that the proposed requirements FAC-001-3-R3.3 and FAC-001-3-R4.3 address specific needs for operating the system and therefore belong in an Operations Standard which is already being covered in requirements of FERC approved TOP-003-3 which describes the information that TOs and GOs are required to provide to the Balancing Authority as specified by the Balancing Authority.

Therefore, GTC respectfully requests this drafting team to remove R3.3 and R4.3 as a proposed change to FAC-001-2 and further clarify the purpose statement of FAC-001 to resolve the ambiguity that this current draft introduced by clarifying the purpose of FAC-001 which should align with FAC-002 by inserting the term “study” within the purpose statement such as:

Purpose: To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection study requirements available so that entities seeking to interconnect will provide the information necessary for studies conducted in accordance with FAC-002-2.

It is GTC's desire that the drafting team utilizes the justification provided by GTC to not move forward with the proposed R3.3 and R3.4 and a refer to TOP-003-3 to demonstrate that there is currently not a reliability gap and also take the time to clarify the purpose statement to resolve the ambiguity introduced with this revision which should not prevent the drafting teams goal of an approved ballot.

Since the requirements currently exist in BAL-005 and were not eliminated as part of P81, there is no debate that they are reliability based. The Drafting Team is proposing relocating them to FAC-001. Unfortunately, the TOP-003-3 data specification would not serve to confirm that a Facility is within the metered boundary of a BAA. Those data specifications are established to truly operate in real-time. The determination that a Facility is within the metered boundaries of a BAA must be determined prior to a new Facility operating. Although the determination that a Facility is within a BAA serves real-time operations, that does not preclude the confirmation of it occurring early than at that time. For example, Seasonal Studies are conducted to assure that proper planning occurs to allow for real-time operations. This confirmation of which BAA will have the Facility within its boundaries occurring during the planning and studying stage is appropriate too since reconciliation of concerns may need to be addressed with this entity.

Likes 0	
Dislikes 0	

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

Answer	
Document Name	

Comment

While the latest proposed revisions to FAC-001-3 are an improvement (by removing the unnecessary R5, R6 and R7), the additions of R3.3 and R4.3 could be better worded, are unnecessary as requirements (they attempt to address an energy accounting problem, not a reliability problem), and likely already included in most Facility Interconnection Requirements documents in the Metering and Telecommunications section under Guidelines and Technical Basis (created in the new FAC-001-2), and/or in interconnection agreements between Facility owners and transmission providers.

If the SDT chooses to retain these requirements, some changes in the wording are warranted: R3.2 reads, "Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections." In order to understand the sentence, it is helpful to make a substitution like the following: "Procedures for notifying [someone] of new [things]."

The new R3.3 reads: “Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area’s metered boundaries.” A simple fix might be to change the word “of” to “that” so that it reads “Procedures for confirming with [someone] that new [things] are within a Balancing Authority Area’s metered boundaries.”.

The Drafting Team does not agree that each Facility being within the metered boundaries of a BAA is an energy accounting issue. If a Facility is not within a BAA, for example a generator, it can cause many reliability issues such as impacting Frequency and flows. This has occurred in the past, which proves the need for this requirement to remain.

Although this information may be included in some Interconnection Requirements, it is not mandated to be in all. If it is already included in those documents, then the entity will likely have little more to do.

Thank you for the suggested language to make the requirement read better. The SDT has made the modification as suggested.

Likes 0	
Dislikes 0	

Teresa Czyz - Georgia Transmission Corporation - 1,3 - SERC

Answer	
Document Name	

Comment

FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC-001 were removed including a requirement for metering and telecommunication.

Additionally, GTC understands that FAC-001 and FAC-002 are complimentary Standards in a sense that FAC-001 requires Transmission Owners or Generator Owners to define the interconnection requirements necessary to collect data from entities such that the Planning Coordinator and Transmission Planners can study the impact of interconnecting new or materially modified Facilities to the BES in accordance with FAC-002.

All of the requirements of FAC-001 are limited to the long-term planning time horizon. Based on the rationale and proposed language provided for R3.3 and R4.3, a new level of ambiguity has presented itself that could lead some to conclude that these interconnection requirements should be expanded beyond the planning horizon and lead up to “commissioning of a Facility” which resides in the operations horizon.

Based on the Ballot supporting material, the proposed FAC-001 R3.3 and R3.4 requirements were originally included in BAL-005-1. The goal of the requirement in BAL-005-1 was to ensure that Area Control Error is calculated properly. Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R3.3, R4.3) would violate paragraph 81 criteria and introduces ambiguity associated with the aforementioned planning horizon vs operations horizon concerns that is currently not addressed in FAC-001 or FAC-002. GTC believes this concern is already covered in operation horizon standards such as TOP-003-3 and IRO-010-2. Specifically, R4 of TOP-003-3 already addresses and requires the BA to distribute its data specification to entities that have data required by the BA analysis functions and Real-time monitoring. Additionally, R5 of TOP-003-3 requires each TOP, GO, GOP, TO, LSE, and DP to satisfy the obligations of the documented specifications.

In summary, GTC believes that the proposed requirements FAC-001-3-R3.3 and FAC-001-3-R4.3 address specific needs for operating the system and therefore belong in an Operations Standard which is already being covered in requirements of FERC approved TOP-003-3 which describes the information that TOs and GOs are required to provide to the Balancing Authority as specified by the Balancing Authority.

Therefore, GTC respectfully requests this drafting team to remove R3.3 and R4.3 as a proposed change to FAC-001-2 and further clarify the purpose statement of FAC-001 to resolve the ambiguity that this current draft introduced by clarifying the purpose of FAC-001 which should align with FAC-002 by inserting the term “study” within the purpose statement such as:

Purpose: To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection study requirements available so that entities seeking to interconnect will provide the information necessary for studies conducted in accordance with FAC-002-2.

It is GTC’s desire that the drafting team utilizes the justification provided by GTC to not move forward with the proposed R3.3 and R3.4 and a refer to TOP-003-3 to demonstrate that there is currently not a reliability gap and also take the time to clarify the purpose statement to resolve the ambiguity introduced with this revision which should not prevent the drafting teams goal of an approved ballot.

Since the requirements currently exist in BAL-005 and were not eliminated as part of P81, there is no debate that they are reliability based. The Drafting Team is proposing relocating them to FAC-001. Unfortunately, the TOP-003-3 data specification would not serve to confirm that a Facility is within the metered boundary of a BAA. Those data specifications are established to truly operate in real-time. The determination that a Facility is within the metered boundaries of a BAA must be determined prior to a new Facility operating.

Although the determination that a Facility is within a BAA serves real-time operations, that does not preclude the confirmation of it occurring early than at that time. For example, Seasonal Studies are conducted to assure that proper planning occurs to allow for real-time operations. This confirmation of which BAA will have the Facility within its boundaries occurring during the planning and studying stage is appropriate too since reconciliation of concerns may need to be addressed with this entity.

Likes 0	
Dislikes 0	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R

Answer	
Document Name	

Comment

The added requirements 3.3 and 4.3 are not clear. The drafting team copied R3.2 approach but it not work for 3.3. In R3.2 the Transmision Owner is notifying the other reliability entities that new or modified interconnection is being pursued. Technically that would include a notice to the BA. But an explicit sub-requirement is needed. Concerns with R3.3 are: 1. Use of word confirming. Confirming is beyond notification; a confirmation requires the TO to maintain the response from the BA and possibly go further and verify the BA is truthful. The SDT reply to the last comments indicated it was really concerned that the BA would not be aware of changes made by TO. 2. The use of phrase “those responsible for the reliability of affected systems” is not needed and should be replaced with ‘responsible Balancing Authority’ since that is the only reliability function implicated by this subrequirement. 3.The BA should be required to provide the procedure for notification from a TO when a new or modified interconnesction is being pursued. Then the TO can align its Interconnection requirements document to the BA process.

We do not support the proposed changes to R3 and R4. The SDT, in the rationale boxes stated “It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA’s metered boundaries”. We do not believe it is appropriate to shift the compliance responsibility of one entity to another and therefore suggests the SDT also include Distribution Provider in the applicability section and then develop a requirement to read “Entity seeking to interconnect (TO, GO or DP) shall confirm with those responsible for the reliability of affected systems that its newly installed or modified Facility is within a Balancing Authority Area’s metered boundaries”

Requirement 3.3 and 4.3 should not be moved to FAC-001-3. The BA is in the best position to know its metered boundaries and confirm if any new or modified transmission or generation project is within those metered boundaries. The proposed R3.3 and R4.3 should remain in BAL-005, but be assigned to the BA. R1 from BAL-005-0.2b should be retained and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

Alternatively the proposed R3.3 and R4.3 could be moved to FAC-002-2. FAC-002-2 is more appropriate than FAC-001-2 for this requirement because FAC-002-2 applies to TOs and GOs "seeking to interconnect" new or modified facilities. Therefore FAC-002-2 is more in line with the SDT's rationale that "It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries…"

A Balancing Authority is not capable of knowing who *should* be requesting to be within its metered boundaries. However, the transmission owner must know and Facilities to which it is connected must have an Interconnection Agreement that identifies which Balancing Authority Area the connecting Facility is within. And, the Transmission Owner is responsible for notifying the Balancing Authority about the Agreement. This notification is essential for reliability reasons and system control considerations.

The SDT considered the option of placing the requirement in FAC-002 but found it more appropriate to transfer this knowledge during the interconnection process.

Likes 0	
Dislikes 0	

William Temple - William Temple

Answer	
Document Name	

Comment

PJM views FAC-001 as a reporting requirement that must be carefully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change." The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirement as part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility owner is required to register with NERC. PJM proposes that as part of that process, the facility owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entity(ies) that are involved.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

It is a proven reliability risk that all Facilities must be within the metered boundaries of a BAA. If not, a Facility such as a generator could harm Frequency without any consequence. Although the implementation of confirming any new and modified facilities (not all existing equipment, as is mentioned in the comment) will take on an administrative nature, that does not diminish its importance in ensuring reliability because it provides added assurance that all facilities are taken into account in planning.

The idea of NERC having a registry is not without merit, but is outside the scope of this Drafting Team.

Likes 0	
Dislikes 0	

Shivaz Chopra - New York Power Authority - 6

Answer	
Document Name	
Comment	

FAC-001-3. ***NYPA has a concern that R3.3 and 4.3 should be the responsibility of the interconnecting entity to ensure their facility is within a BA's metered boundary***.

The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Likes 0	

Dislikes 0	
Dixie Wells - Lower Colorado River Authority - 5, Group Name LCRA Compliance	
Answer	
Document Name	
Comment	

The SDT should consider the impact of new requirements R3.3 and R4.3 in regions where a single BA exists. These requirements would not seem to apply in cases such as ERCOT, where clearly any TO or GO facility additions are within the one and only BA's metered boundaries.

Recommend the standard language additions:
3.3 In regions with multiple Balancing Authorities, procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

4.3 In regions with multiple Balancing Authorities, Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

The SDT agrees with your concern, but this consideration is addressed in the purpose of the requirement. The purpose of the requirement is to be certain that the entity has joined a BAA, regardless of the number of options available to them. Just because they can only join one BAA, does not mean that they did. As such, the SDT does not believe this conforming modification is necessary.

Likes 0	
Dislikes 0	
John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	

na	
Likes 0	
Dislikes 0	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	
Document Name	
Comment	

Duke Energy is not certain that the current language in R3.3 and R4.3 of the proposed FAC-001-3 adequately establishes that it is the responsibility of the interconnecting entity to make the necessary arrangements, and that the Transmission Owner is responsible for confirming with a Generator, who their Balancing Authority will be. We feel that this intent is clear from reading the Rationale for R3, but do not feel that this intent is ascertainable by reading R3.3 on its own. Duke Energy suggests the following revisions to R3.3 and R4.3 to add clarity:

R3.3: Procedures for confirming that new or materially modified transmission Facilities are accurately telemetered, modeled, and accounted in Real-time systems of the Balancing Authority(s) designated by the interconnecting entity.

R4.3: Procedures for confirming that new or materially modified generation Facilities are accurately telemetered, modeled, and accounted in Real-time systems of the Balancing Authority(s) designated by the interconnecting entity.

We feel that these modifications and the resulting modifications to the Guidelines and Technical Basis section of the standard, better illustrates the intent of the drafting team, without needing the requirements' rationale to decipher said intent.

Also, Duke Energy suggests a minor modification to language used in the sub-requirements of R3 and R4. We suggest the use of the term Procedure[s] with the [s] accompanying. This clears up ambiguity that could arise in the event that an entity only has one procedure that is applicable to these requirements.

The Drafting Team appreciates the feedback. The SDT recognizes that this is an issue in all NERC Reliability Standards. The Alignment of Terms SDT will be addressing this issue. For additional information please refer to Arizona Public Service comments and our associated response on pages 75 and 76 of this report. The SDT contends that this not be limited to one and only one BA and the SDT recognizes that multiple BAs may be involved. But the Drafting Team believes it is not reasonable or appropriate for the TO or applicable GO to assess how the BAA has incorporated "accurately" the entity into their BAA systems. Since all BAAs are certified, we can assume if the entity has an agreement for them to be in their BAA, that BAA has the ability to incorporate them into their systems appropriately.	
Likes 0	
Dislikes 0	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
APS agrees with the approach for Requirements R3.3 and R4.3, in that it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority, and that the Transmission Owner or Generation Owner is responsible for confirming that the party interconnecting to make appropriate arrangements with a Balancing Authority. Since Transmission Owners and Generation Owners may receive either transmission or generation interconnection requests, APS recommends revising the requirements as follows: **R3.3** – Procedures for confirming with **the associated Balancing Authority that the** new or materially modified **generation and/or** transmission Facilities, that those generation and/or transmission Facilities are within **its** metered boundaries. **R4.3** – Procedures for confirming with **the associated Balancing Authority that the** new or materially modified **generation and/or** transmission Facilities, that those generation and/or transmission Facilities are within **its** metered boundaries. **R3.3**	

The drafting team has made conforming modifications to Requirement R3.3 to accurately reflect the intent of the drafting team, as described in the Rationale for R3.3. As stated in the Rationale, "it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority *to ensure its Facilities are within the BA's metered boundaries*, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation." Additionally, the "Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries." By removing the term "transmission," Requirement R3.3 more clearly reflects the fact that a Transmission Owner properly addresses procedures for confirming that those responsible for reliability of the *applicable* affected systems are within a Balancing Authority Area's metered boundaries. This change promotes reliability because it ensures confirmation that all entities that affect reliability share relevant information because they are within a Balancing Authority Area's metered boundaries.

R4.3

The drafting team has made conforming modifications to Requirement R4.3 to accurately reflect the intent of the drafting team, as described in the Rationale for R4.3. As stated in the Rationale, "it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority *to ensure its Facilities are within the BA's metered boundaries*, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation." Additionally, the "Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries." By removing the term "generation," Requirement R4.3 more clearly reflects the fact that a Generator Owner properly addresses procedures for confirming that those responsible for reliability of the *applicable* affected systems are within a Balancing Authority Area's metered boundaries. This change promotes reliability because it ensures confirmation that all entities that affect reliability share relevant information because they are within a Balancing Authority Area's metered boundaries.

Likes 0	
Dislikes 0	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	

Document Name	
Comment	

ReliabilityFirst agrees the draft FAC-001-3 draft standard but offers the following comments for consideration.

1. **Requirement 3, Part 3.3**

    i. **Part 3.3 uses the term "materially modified". RF believes this term is ambiguous and requests the SDT further clarify what is considered a "materially modified transmission Facility".**

2. **Requirement 4, Part 4.3**

    i. **Part 4.3 uses the term "materially modified". RF believes this term is ambiguous and requests the SDT further clarify what is considered a "materially modified generation Facility".**

"Materially modified" was used in Requirement R3.1, R3.2, R4.1, and R4.2 of the current standard and the SDT used the same language for consistency and felt since it was previously approved we believe that it is clear, from experience, that the industry understands the meaning.

Likes 0	
Dislikes 0	

Jonathan Appelbaum - United Illuminating Co. - 1	
Answer	
Document Name	
Comment	

1. R3.2 has the TO establishing a procedure to provide a notification whle R3.3 requires a confirmation. What is the difference in actions between notification and confirmation? Who or what is to be confirmed? The technical and guideline section should explain what the confirmation is supposed to be.

2. Do requirements R3.2 and R3.3 means the TO must perform this confirmation or can the procedure require the interconnecting party perform the confirmation? UI believes the TO establishes the procedure, or writes into its interconnection document the BA's process,

but the requirements document can require the interconnecting party to perform the notifiction and confirmation. If so, this should be added to the Technical Guideline section of Standard.

3. What is the purpose of R3.3 requiring a confrimation with " those responsible for the reliability of affected systems" instead of just stating the Balancing Authority. It should be the BA.

This is my proposed addition to Techincal Guideline section to address my comments 1 to 3:

"R3.2 requires the TO to establish a procedure to notify those responsible for the reliability of affected system(s) of new or materially modified existing interconnections. Notification means that the TO, requires either itself or the interconnecting party to contact the relevant reliability authorities and provide notice of the facility. R3.3 requires the TO to establish a procedure to confirm that a facility is within a metered boundary of a BA. Confirmation means that the TO, requires either itself or the interconnecting party to contact the BA and receive a letter of confirmation that the facility is in the BA metered boundary. The requirement and measure for R3 is only that the processes are established in the requirements document. The requirements document may reference a market or tariff as its process."

4. If proposed R3.3 was to be approved then it is missing the word "that". It should state: "Procedures for confirming with those responsible for the reliability of affected systems **that** new or materially modified transmission Facilities are within a Balancing Authority Area’s metered boundaries.."

The purpose of *confirmation* is to be certain that the information associated with the Facility has been transferred to the appropriate BA. The TO or applicable GO would not know who to “notify” until they have confirmed there is a BAA to notify.

Thank you for your language suggestions. The SDT has modified the requirement for clarity. The Drafting Team does not prescribe how the applicable entity would draft their procedure[s] to accomplish the objective of confirming a BAA exists for the Facility. Each entity can decide how the outcome is achieved.

Likes 0	
Dislikes 0	

Douglas Webb - Douglas Webb

Answer	
Document Name	
Comment	

KCP&L does not support the proposed revisions to FAC-001-3 R3.3 and recommends not adopting the Requirement. The proposed revised Standard is applicable to KCP&L as a registered Transmission Owner and, potentially, as a registered Generator Owner.

Requirement 3.3

R3.3 creates a compliance obligation for a disinterested party. The proposed R3.3, in effect, requires the Transmission Owner to create a procedure to promote the exchange of information between a third party Facility interconnecting with a Generator Owner whose facility is used to connect to the Transmission system. The procedure developed by the Transmission Owner must identify "affected systems," confirm who is responsible for reliability of the "affected systems," and, confirm with the "affected systems" owner that new interconnected facilities are within the metered boundaries of the identified Balancing Authority.

The difficulty with R3.3, as proposed, is evident when compliance scenarios are considered. For example, the Transmission Owner creates the required procedure under R3.3. The rationale—the compliance goal—for R3.3 centers on a duty by of the party interconnecting (PI) to make appropriate arrangements with the BA to ensure the PI Facilities are within the BA's metered boundaries. If the PI fails to fulfill its duty, it raises the question: Where is the noncompliance under R3.3? The Transmission Owner created the procedure, as required, yet, the stated rationale, goal, is not accomplished.

To achieve the stated rationale's goal, It would seem the compliance duty should fall to the party interconnecting. Absent that, the Balancing Authority and/or the Generator Owner whose facilities are used to interconnect to the transmission system would be in a better position to address Balancing Authority Area's metered boundaries. Also, the Requirement seems redundant since there are active NERC Standards requiring Generator Owners to inform Transmission Owners of changes to the GOs' facilities and Transmission Owners informing BA of new interconnections. Finally, from a practical viewpoint, it is just not likely a PI would connect without metering and SCADA connections—all such activity providing visibility to the BA and TO of changes to the system.

KCP&L recommends removing R3.3 or, in the alternative, suggests deleting "with those responsible for the reliability of affected systems of" from the proposed R3.3.

R3.3: "Procedures for confirming ~~with those responsible for the reliability of affected systems of~~ new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries."

"Affected System"

Generally, defined terms better serve compliance with Standards and implementation of Requirements. The term, "affected system" is not defined. FERC approved *pro forma* interconnection agreements define the term as, "...an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection." KCP&L believes there may be benefit aligning the undefined NERC Standard terms relating to interconnection facilities with equivalent FERC *pro forma* interconnection agreements defined terms. While such an effort would require substantial effort to address all affected Standards, for the purposes of this Standard, we would encourage adopting FERC's *pro forma* definition for the proposed revision to FAC-001-3.

The SDT believes that the lack of confirmation would indicate their procedure inadequate.

The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Likes 0	
Dislikes 0	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT supports the comments of the IRC SRC. The comments are provided below:

The SRC views FAC-001 as a reporting requirement that must be carfully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change". The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirmentas part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility own should be required to register with NERC. The SRC proposes that as part of that process the owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entitiy(ies) that will be changed.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

It is a proven reliability risk that all Facilities must be within the metered boundaries of a BAA. If not, a Facility such as a generator could harm Frequency without any consequence. Although the implementation of confirming any new and modified facilities (not all existing equipment, as is mentioned in the comment) will take on an administrative nature, that does not diminish its importance in ensuring reliability because it provides added assurance that all facilities are taken into account in planning.

The idea of NERC having a registry is not without merit, but is outside the scope of this Drafting Team.

Likes 0	
Dislikes 0	

Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment

This standard should not be a reliability standard, the contents of the standard do nothing to improve the reliability of the system.

The SDT disagrees that confirming all Facilities are within a BAA metered boundary does not improve the reliability of the system. An example of how this could negatively impact reliability is when a generator that has not transferred the knowledge that it is within a BA and thus may have an impact on control and Frequency.

Likes 0	
Dislikes 0	

Chris Scanlon - Exelon - 1, Group Name Exelon Utilities

Answer	
Document Name	

Comment

Exelon thinks R3 (and R4) needs to be re-written. We suggest:

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements for new or materially modified existing interconnections:

3.1. Procedures for coordinated studies of new or materially modified interconnections and impacts on affected system(s).

3.2. Procedures for notifying responsible entities of affected systems identified in part 3.1.

3.3. Procedures for confirming with responsible entities that that the new or modified Facilities are within a Balancing Authority Area's metered boundaries.

We also note that the phrase "materilaly modifed" may be subject to interpretation during an audit. The Guideline and Technical Basis section allows the use of engineering judgement when determing what is "material". It seems to beg the question, if an entity is using it's interconnection process and associated procedures as required by the Standrd, the change is material. Has the SDT considerd removing material from the language? This phrase is not defined or used in any other standard other than FAC-001 and 002. We believe either of these changes are non-substantive and would not require an additional comment period.

"Materially modified" was used in Requirement R3.1, R3.2, R4.1, and R4.2 of the current standard and the SDT used the same language for consistency and felt since it was previously approved we believe that it is clear, from experience, that the industry understands the meaning.

Likes 0	
Dislikes 0	

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee

Answer	
Document Name	
Comment	

The SRC views FAC-001 as a reporting requirement that must be carfully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change". The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirmentas part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility own should be required to register with NERC. The SRC proposes that as part of that process the owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entitiy(ies) that will be changed.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

"Materially modified" was used in Requirement R3.1, R3.2, R4.1, and R4.2 of the current standard and the SDT used the same language for consistency and felt since it was previously approved we believe that it is clear, from experience, that the industry understands the meaning.

Likes 0	
Dislikes 0	
Kelly Dash - Kelly Dash, Group Name Con Edison	
Answer	
Document Name	
Comment	

Requirement 3.3 and 4.3 should not be moved to FAC-001-3. The BA is in the best position to know its metered boundaries and confirm if any new or modified transmission or generation project is within those metered boundaries. The proposed R3.3 and R4.3 should remain in BAL-005, but be assigned to the BA. R1 from BAL-005-0.2b should be retained and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

Alternatively the proposed R3.3 and R4.3 could be moved to FAC-002-2. FAC-002-2 is more appropriate than FAC-001-2 for this requirement because FAC-002-2 applies to TOs and GOs "seeking to interconnect" new or modified facilities. Therefore FAC-002-2 is more in line with the SDT's rationale that "It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries…"

The Interconnecting Party decides which BAA they are going to be within, not the BAA. A Balancing Authority is not capable of knowing who *should* be requesting to be within its metered boundaries, nor can they require someone to be inside their BAA. For reliability reasons, we must confirm they have transferred the knowledge to at least one BA. The Drafting Team believes this confirmation occurring as part of the Interconnection process is more appropriate than when the studies are occurring in FAC-002. The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Likes 0	
Dislikes 0	

Glenn Pressler - CPS Energy - 1,3,5

Answer	
Document Name	

Comment

this needs work & here my support for the overall theme of comments submitted by MRO-NSRF, SCR, and also Oncor.

Thank you for your comment. Please refer to our responses to the entities mentioned above.

Likes 0	
Dislikes 0	

Jeremy Voll - Basin Electric Power Cooperative - 3

Answer	
Document Name	
Comment	

R3.3 and R4.3: The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. The FAC-001-2 requirement to have verification of this will just lead to a paper exchange where TO, GO, will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. This provides no incremental reliability value. Recommend to remove this Requirement.

The Drafting Team disagrees that confirming all Facilities are within a BAA metered boundary does not improve the reliability of the system. It is a proven reliability risk that all Facilities must be within the metered boundaries of a BAA. If not, a Facility such as a generator could harm Frequency without any consequence. Although the implementation of confirming any new and modified facilities (not all existing equipment, as is mentioned in the comment) will take on an administrative nature, that does not diminish its importance in ensuring reliability because it provides added assurance that all facilities are taken into account in planning.

Likes 0	
Dislikes 0	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	
Document Name	
Comment	

R3.3 and R4.3 The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. The FAC-001-2 requirement to have verification of this will just lead to a paper exchange where TO, GO, will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. This provides no incremental reliability value. Recommend to remove this Requirement.

The Drafting Team disagrees that confirming all Facilities are within a BAA metered boundary does not improve the reliability of the system. It is a proven reliability risk that all Facilities must be within the metered boundaries of a BAA. If not, a Facility such as a generator could harm Frequency without any consequence. Although the implementation of confirming any new and modified facilities (not all existing equipment, as is mentioned in the comment) will take on an administrative nature, that does not diminish its importance in ensuring reliability because it provides added assurance that all facilities are taken into account in planning.	
Likes 0	
Dislikes 0	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP is in support of the proposed FAC-001-3 Thank you.	
Likes 0	
Dislikes 0	

Tammy Porter - Tammy Porter	
Answer	
Document Name	
Comment	
Oncor does not support the proposed changes to R3. The SDT, in the rationale box states “the Transmission Owner is responsibile for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered	

boundaries". Oncor does not believe that the Transmission Owner should be responsible for the compliance of the interconnecting Transmission Owner. Therefore, Oncor recommends changing R3.3 to the following: "3.3. Requirement that new or materially modified transmission Facilities of the interconnecting Transmission Owner are within a Balancing Authority Area's metered boundaries."

The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Likes 0	
Dislikes 0	

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	
Document Name	

Comment

Provided in ACES Comments

Likes 0	
Dislikes 0	

Louis Slade - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion does not support the proposed changes to R3 and R4. The SDT, in the rationale boxes stated "It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries". Dominion does not believe it is appropriate to shift the compliance responsibility of one entity to another and therefore suggests the SDT also include Distribution Provider in the applicability section and then develop a requirement to read "Entity seeking to

interconnect (TO, GO or DP) shall confirm with those responsible for the reliability of affected systems that its newly installed or modified Facility is within a Balancing Authority Area's metered boundaries" The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.	
Likes 0	
Dislikes 0	

End of Report