Comment Report

Project Name:	2016-02 Modifications to CIP Standards | CIP-002-6
Comment Period Start Date:	8/23/2018
Comment Period End Date:	10/9/2018
Associated Ballots:	2016-02 Modifications to CIP Standards CIP-002-6 Draft 1 IN 1 ST

There were 61 sets of responses, including comments from approximately 150 different people from approximately 101 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Attachment 1, Criterion 2.6: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.6? If not, please provide your rationale and an alternate proposal.

2. Attachment 1, Criterion 2.9: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.9? If not, please provide your rationale and an alternate proposal.

3. Attachment 1, Criterion 2.12: No changes have been added from the previous ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

4. Guidelines and Technical Basis: Do you agree with the proposed modifications to Criterion 2.6 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

5. Guidelines and Technical Basis: Do you agree with the proposed modifications to Criterion 2.9 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

6. Implementation Plan: The SDT proposes an Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is fifteen (15) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

7. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Rodger Blakely	Santee Cooper	1,3,5,6	SERC
					Troy Lee	Santee Cooper	1,3,5,6	SERC
					Jennifer Richards	Santee Cooper	1,3,5,6	SERC
					Chris Jimenez	Santee Cooper	1,3,5,6	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO

					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Lincoln Electric System	Eric Ruskamp	6		LES	Eric Ruskamp	Lincoln Electric System	6	MRO
					Dan Pudenz	Lincoln Electric System	1	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO
ACES Power Marketing	Jodirah Green	6	NA - Not Applicable	ACES Standard Collaborations	Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Joseph Smith	Prairie Power	3	SERC

					Susan Sosbe	Wabash Valley Power Association	3	RF
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
FirstEnergy - FirstEnergy Corporation	Julie Severino	1		FirstEnergy	Aubrey Short	FirstEnergy - FirstEnergy Corporation	4	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and HQ	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

Wayne Sipperly	New York Power Authority	4	NPCC
Glen Smith	Entergy Services	4	NPCC
Brian Robinson	Utility Services	5	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Laura Mcleod	NB Power	1	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Helen Lainis	IESO	2	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Michael Forte	Con Ed - Consolidated Edison	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Sean Cavote	PSEG	4	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC

					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC

					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Attachment 1, Criterion 2.6: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.6? If not, please provide your rationale and an alternate proposal.

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
The undefined term 'instability' could expand the scope of both medium and high impact cyber asset classification. Potentially, every BES generator and every BES Transmission Cyber Asset would meet the medium impact criteria. Generators with a Control Center at the facility could be classified as high impact Cyber Assets, whether or not an IROL was impacted. With the requirement not having any minimum threshold for generator BCSs, the criteria could be interpreted to apply to any BES generator. Dominion Energy recommends that the term 'instability' be eliminated from any of the Requirements and Attachments in CIP-002-6. If the SDT chooses to leave the term 'instability' in CIP-002-6, Dominion Energy recommends that this term be limited to Wide Area imacts, as outlined in the Guidelines and Technical Basis document for criteria 2.9 of Appendix 1. This would be consistent with the scope of CIP-014 that lmits the scope to instability within an Interconnection.	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP - 3	
Answer	No
Document Name	
Comment	
AEP does not believe the proposed draft language in Criterion 2.6 properly address the issue of notification. A Responsible Entity would have no way of knowing the results of these studies unless the PC and/or TP functions are performed internally. AEP understands that a requirement for the TP or PC to communicate this status to Responsible Entities, primarily GOs and TOs, has been proposed for FAC-015-1, R4. The language in Criterion 2.6 should incorporate words that indicate the source Entity is the TP or PC. In addition, AEP is not convinced that the RC should be removed from this Criterion. With these ideas in mind, AEP suggests the SDT consider the language for Attachment Criterion 2.6 that follows: *"Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator, Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation when* ***notified by the Reliability Coordinator, Transmission Planner, or Planning Coordinator.*** *"*	
Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	

Comment

The NSRF proposes the following new wording for Criterion 2.6. which is similar to the present wording, “Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies”.

This proposed alternate wording is based on the following considerations;

[1] Compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated before the Operations Planning Horizon begins. So, no Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners will identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

[2] Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards. In addition, the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2105-09 will continue to require Reliability Coordinators to establish operating horizon IROLs that prevent instability, Cascading, and uncontrolled separation from occurring.

[3] The new wording retains the bright line nature of Criterion 2.6, rather than the proposed revision will require supplementary analysis to evaluate the applicability operating horizon IROLs.

Likes 0	
Dislikes 0	

Response

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	No
Document Name	

Comment

LES supports the following NSRF comments:

The NSRF proposes the following wording for Criterion 2.6. which is similar to the present wording, “Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies”.

This proposed alternate wording is based on the following considerations;

[1] Compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated before the Operations Planning Horizon begins. So, no Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners will identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

[2] Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards. In addition, the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2105-09 will continue to require Reliability Coordinators to establish operating horizon IROLs that prevent instability, Cascading, and uncontrolled separation from occurring.

[3] The new wording retains the bright line nature of Criterion 2.6, rather than the proposed revision will require supplementary analysis to evaluate the applicability operating horizon IROLs.

Likes 0	
Dislikes 0	

Response

Vivian Vo - APS - Arizona Public Service Co. - 3

Answer	No
Document Name	

Comment

AZPS is not in agreement with the proposed modifications to CIP-002-6 Attachment 1, Criterion 2.6. There are several reasons for AZPS's disagreement. The first is that, in reviewing this language, AZPS interprets the proposed modification as resulting in a change to the previous language and the underlying obligation - not simply a movement or revision of language as proposed in the SAR. More specifically, the intent of the SAR was to maintain the intent and underlying obligations of CIP-002-6 Attachment 1, Criterion 2.6 while accommodating revisions to other reliability standards. Thus, a modification of the underlying obligation and impact of CIP-002-6 Attachment 1, Criterion 2.6 is not what the SAR intended. The proposed modification results in an expansion of the underlying obligations of Responsible Entities that will identify new and different facilities. For this reason, the proposed modification goes beyond what is necessary to accommodate the change from the other Standard. It is notable that the previous language hinged upon those facilities critical to the derivation of an IROL while the modification completely shifts the focus to those facilities that would result in system instability, cascading, or controlled separation. This is significant and forms our second reason for disagreement with the proposed modification.

In particular, the second reason is that not all events that result in system instability, cascading, or controlled separation would result in an IROL. Thus, not all facilities that, if lost or degraded, would result in an IROL or the derivation of an IROL, which was previously the focus of this requirement. This modification, therefore, pulls in results and facilities implicated during “extreme events” as defined in TPL-001-4, which is too broad and a far distance from the previous intent of CIP-002-6 Attachment 1, Criterion 2.6.

Finally, the third reason for AZPS's disagreement is the fact that the Transfer Capability Study is not intended to stress the system in those ways that would reveal an IROL. These studies are designed to identify those transfers that can be reliably accommodated. Exceedance of reliable accommodation of a transfer does not automatically translate to either the occurrence of system instability, cascading, or controlled separation or an IROL. Accordingly, the proposed modification goes beyond the current intent of CIP-002-6 Attachment 1, Criterion 2.6 and the intent of the SAR.

To ensure consistency with the intent of CIP-002-6 Attachment 1, Criterion 2.6 and the SAR associated with the proposed modification, APS proposes the following language for Criterion 2.6. This revision also clarifies that CIP-002-6 Attachment 1, Criterion 2.6 is not applicable to Extreme Events that are also studied with the Planning Assessment:

2.6 Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Planning Coordinator or Transmission Planner as an element of each P0 – P7 Contingency event included in the Planning Assessment that result in System instability, Cascading or uncontrolled separation.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment

NV Energy is concerned that the use of term 'instability', within the context of Criterial 2.6, represents an untenable expansion of the scope for CIP-002-6. Our concerns rest on the belief that the proposed language in Criterion 2.6, if approved, could require many entities to reclassify substantial numbers of BES cyber assets to medium impact, while creating the potential for other BES cyber assets to be reclassified to high impact, while posing little to no known risk to BES reliability.

NV Energy suggests the insertion of "Wide Area impact" into the requirement to be consistent with the supplemental material for Criterion 2.9 when referencing "instability, Cascading, or uncontrolled separation." Example language follows:

"2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of Wide Area impacts such as instability, Cascading, or uncontrolled separation."

Alternatively, should the SDT chooses to leave the term 'instability' within CIP-002-6, NV Energy suggests minimizing the scope through language similar to what is currently used in the GTB for Criterion 2.9 which ties the term instability to Wide Area impacts. This would be consistent with the scope of CIP-014 that limits the scope of instability to within an Interconnection.

The Near-Term Planning Horizon is one to five years. The implementation period is calculated from the "date of notification or detection of the Unplanned Change." The Assessment/assessment projects a year when the Facilities are expected to result in instances of instability, Cascading, or uncontrolled separation. The date of notification or detection of the Unplanned Change per the implementation period shall be calculated as follows. The year identified in the Assessment/assessment minus the 12 or 24 month implementation period, except for the following:

- The TPL-001-4 R2.7 Corrective Action Plan(s) addresses how the performance requirements will be met and include a required timeframe. If the timeframe is:
    - prior to the projected year in the Assessment/assessment, then the Facility is not identified as medium impact per this criteria and no implementation is required.
    - after the projected year in the Assessment/assessment, then the Facility is identified as medium impact per this criteria and the implementation plan for unplanned changes applies.

The Responsible Entity shall have at least the 12 or 24 months implementation period per the implementation plan for unplanned changes.

Likes 0	

Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	No
Document Name	
Comment	
We are concerned that the language in Criteria 2.6 could cause new generation assets to be identified as needing to meet CIP-002-6 medium/high impact criteria for a short time frame until a Corrective Action Plan could be implemented. Additionally, current generation that is not medium could possibly become medium as other generation is retired if the retirement caused a change in IROLs. Could the language be modified to be a "newly identified issue that will not be obviated within 3 years"?	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
Insert Wide Area impact into the requirement to be consistent with the supplemental material for Criterion 2.9 when referencing "instability, Cascading, or uncontrolled separation." Example language follows:	

"2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of Wide Area impacts such as instability, Cascading, or uncontrolled separation."

The standard must provide clarity on timing in 2.6 with the addition of Near-Term Planning Horizon. For example, a Facility projected to be medium impact five years out, should not be subject to CIP compliance in year one. Also, an entity should have, at a minimum, the months in the implementation plan for unplanned changes. Example language follows.

The Near-Term Planning Horizon is one to five years. The implementation period is calculated from the "date of notification or detection of the Unplanned Change." The Assessment/assessment projects a year when the Facilities are expected to result in instances of instability, Cascading, or uncontrolled separation. The date of notification or detection of the Unplanned Change per the implementation period shall be calculated as follows. The year identified in the Assessment/assessment minus the 12 or 24 month implementation period, except for the following:

- The TPL-001-4 R2.7 Corrective Action Plan(s) addresses how the performance requirements will be met and include a required timeframe. If the timeframe is:
    - prior to the projected year in the Assessment/assessment, then the Facility is not identified as medium impact per this criteria and no implementation is required.
    - after the projected year in the Assessment/assessment, then the Facility is identified as medium impact per this criteria and the implementation plan for unplanned changes applies.
- The Responsible Entity shall have at least the 12 or 24 months implementation period per the implementation plan for unplanned changes.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy is unclear on the language, and the necessity of bringing the Elements in as they are proposed in this standard. First, the terms System instability, Cascading, or uncontrolled separation may be interpreted differently depending on the PC/TP. The proposed criteria introduce a level of subjectivity that was intentionally eliminated from Version 5. Second, the term "Planning Assessment" is used which includes evaluation of Extreme Events under TPL-001. Providing a Medium impact classification to Facilities that are only identified during an Extreme Event is inappropriate. Third, with respect to generation, criterion 2.3 currently addresses a generation Facility that has been designated to avoid an Adverse Reliability Impact. The proposed criterion 2.6 is potentially duplicative with respect to generation. Fourth and most importantly, TP/PC identified SOLs/IROLs are proposed to be removed from the FAC standards. We are unclear why identification would be unnecessary in FAC-010, but those same Facilities that would have been identified are important enough to be labeled as Medium impact in this CIP standard.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

Insert Wide Area impact into the requirement to be consistent with the supplemental material for Criterion 2.9 when referencing "instability, Cascading, or uncontrolled separation."

Example language follows:

"2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of **Wide Area** impacts such as instability, Cascading, or uncontrolled separation."

The standard must provide clarity on timing in 2.6 with the addition of Near-Term Planning Horizon. For example, a Facility projected to be medium impact five years out, should not be subject to CIP compliance in year one. Also, an entity should have, at a minimum, the months in the implementation plan for unplanned changes. Example language follows.

The Near-Term Planning Horizon is one to five years. The implementation period is calculated from the "date of notification or detection of the Unplanned Change." The Assessment/assessment projects a year when the Facilities are expected to result in instances of instability, Cascading, or uncontrolled separation. The date of notification or detection of the Unplanned Change per the implementation period shall be calculated as follows. The year identified in the Assessment/assessment minus the 12 or 24 month implementation period, except for the following:

The TPL-001-4 R2.7 Corrective Action Plan(s) addresses how the performance requirements will be met and include a required timeframe. If the timeframe is:

-- prior to the projected year in the Assessment/assessment, then the Facility is not identified as medium impact per this criteria and no implementation is required.

--after the projected year in the Assessment/assessment, then the Facility is identified as medium impact per this criteria and the implementation plan for unplanned changes applies.

--The Responsible Entity shall have at least the 12 or 24 months implementation period per the implementation plan for unplanned changes.

Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC is concerned that the proposed changes eliminate consideration of Operating Horizon IROLs and may pose unintended consequences for security and reliability because the proposed wording will eliminate consideration of Facilities critical to the derivation of Operations Planning horizon IROLs. This change would eliminate the identification (and subsequent protection) of medium impact BES Cyber Systems that have a medium reliability impact in the Operations Planning horizon, but do not have a medium reliability impact in the Near-Term Planning horizon.

For this reason, ATC requests SDT consideration of the following wording for Criterion 2.6. which is similar to the present wording, “Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies”.

This proposed alternate wording is based on the following considerations:

[1] Compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated before the Operations Planning Horizon begins. So, no Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners will identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

[2] Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards. In addition, the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2105-09 will continue to require Reliability Coordinators to establish operating horizon IROLs that prevent instability, Cascading, and uncontrolled separation from occurring.

[3] The new wording retains the bright line nature of Criterion 2.6, rather than the proposed revision will require supplementary analysis to evaluate the applicability operating horizon IROLs.

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

EEI is concerned that the use of term ‘instability’, within the context of Criterial 2.6, represents an untenable expansion of the scope for CIP-002-6. Our concerns rest on the belief that the proposed language in Criterion 2.6, if approved, could require many entities to reclassify substantial numbers of BES cyber assets to medium impact, while creating the potential for other BES cyber assets to be reclassified to high impact, while posing little to no known risk to BES reliability. Whereas we recognize the term ‘instability’ is broadly understood and used in the definition of many terms defined within the NERC Glossary of Terms, it has always been limited in scope to specific reliability impacts to the Bulk Electric Systems. While EEI cannot accurately quantify the broad impacts of this proposed change, we understand that the potential exists for virtually every BES generator and BES Transmission Cyber Asset to be reclassified under the medium impact criteria. Additionally, we also understand that many generators with a Control Center within the physical boundaries of that facility would also likely to become high impact BES Cyber Assets, whether or not an IROL was impacted. Therefore, without some limiting minimum threshold that might inform companies as to the intended scope of these changes we cannot support the proposed changes.

Alternatively, should the SDT chooses to leave the term 'instability' within CIP-002-6, EEI suggests minimizing the scope through language similar to what is currently used in the GTB for Criterion 2.9 which ties the term instability to Wide Area impacts. This would be consistent with the scope of CIP-014 that limits the scope of instability to within an Interconnection.

Additionally, EEI is concerned that existing language used in Criterion 2.6 could be interpreted to mean that a BES Cyber System identified over the Near-Term Transmission Planning Horizon as Medium Impact could be understood to mean that an entity would be required to demonstrate CIP compliance within 12 or 24 months (See Scenario of Unplanned Change, page 6) from its initial identification even if the BES Cyber System would not be impacted until year five. For this reason, we ask the SDT to consider adding language similar to that used within TPL-001-4, Requirement 2.7, which we believe would remove all ambiguity.

Likes 0	
Dislikes 0	

Response

Randy MacDonald - NB Power Corporation - 1

Answer	No
Document Name	

Comment

Does "Facilities lost or degraded" correlate with those events in table 1 of TPL-001-4? If not please point to the PC/TP Planning Assessment requirements that would identify those Facilities under section 2.6.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

ITC Supports the comments filed by the NSRF:

The NSRF proposes the following new wording for Criterion 2.6. which is similar to the present wording, "Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Reliability Coordinator as Facilities, that, if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies".

This proposed alternate wording is based on the following considerations;

[1] Compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances to be identified and mitigated before the Operations Planning Horizon begins. So, no Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners will identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

[2] Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards. In addition, the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2105-09 will continue to require Reliability Coordinators to establish operating horizon IROLs that prevent instability, Cascading, and uncontrolled separation from occurring.

[3] The new wording retains the bright line nature of Criterion 2.6, rather than the proposed revision will require supplementary analysis to evaluate the applicability operating horizon IROLs.

Likes 0	
Dislikes 0	

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") believes the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.6 is inconsistent with the Near-Term Planning Assessment required for TPL-001-4. It is also unclear whether the Planning Assessment required for TPL-001-4 can be used for Criterion 2.6 or additional studies are required.

Additionally, CenterPoint Energy is concerned that existing language used in Criterion 2.6 could be interpreted to mean that a BES Cyber System identified over the Near-Term Transmission Planning Horizon as Medium Impact could be understood to mean that an entity would be required to demonstrate CIP compliance within 12 or 24 months (See Scenario of Unplanned Change, page 6) from its initial identification even if the BES Cyber System would not be impacted until year five. For this reason, we ask the Standard Drafting Team (SDT) to consider adding language similar to that used within TPL-001-4, Requirement 2.7, which we believe would remove all ambiguity.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

The PC and TP are not listed in the Applicability Section, nor are they associated with the Operations Planning Horizon. Listing them as responsible and providers of the list of Facilities without a direct linkage in the functional model may cause missing some facilities.

as for the removal of the RC from the criteria, there is concern regarding any identified PERMANENT IROLs that may be identified that will not be elevated under CIP concerns. WAPA agrees that temporary local instances of instability should not warrant elevated CIP concern, but does support industry concerns regarding removing the RC from the criteria.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

The term “instability” is without limitation and, as such, has wide ranging implications for entities as they reassess low, medium, and high BES Cyber Systems impacts.

The companies recommend rationalizing “instability” with the NERC Glossary Term “System.”

System: “A combination of generation, transmission, and distribution components.”

The proposed revision:

“…Facilities, that, if lost or degraded are expected to result in instances of **System** instability, Cascading, or uncontrolled separations.”

This recommendation also aligns with the NERC Glossary Term, Cascading, “…loss of system elements…”; and uncontrolled separations.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company's main concern with the proposed change is not the substitution of the IROL term with the three outcomes – instability, Cascading, or uncontrolled separation – our main concern is the prescriptive nature of naming Planning Coordinator studies in Criteria 2.6 to consider, which is beyond existing IROL methodologies, and the use of the unbounded term "instability".

The original CIP-002-5.1a language was specific to IROLs and Southern Company, like many other companies, has an IROL methodology that is largely based in RC and PC stability input. The new Draft CIP-002-6 shifts to the PC/TP and to the three outcomes and goes on to reference two specific studies we relate to TPL-001-4/-5 and FAC-013. This significantly alters the previous requirement language into a new requirement as these two studies were not the basis of the IROL methodology. We suggest that references to specific compliance-based studies such as TPL-001 and FAC-013 be removed and allow the use of in-place proven study methodologies to determine and communicate scenarios that are realistic potential instances of instability, Cascading, or uncontrolled separation.

Considering how current PC analysis addresses or may be used, TPL-001-4 Extreme Events steady-state requires consideration of Item 2c loss of a switching station or substation (loss of one voltage level plus transformers), and Item 2d loss of all generating units at a generating station. The issue we have is TP is not required to look at all Transmission Facilities at a single station or substation – only one voltage level. Additionally, TPL-001-4 only requires performing a steady-state analysis for items 2c and 2d – but not stability. TPL-001-4 R6 requires an Entity to define a methodology to analyze Cascading, voltage instability, or uncontrolled islanding. Per this methodology, Cascading is analyzed with the steady-state and stability modeling, and the other two are only part of stability (dynamic study) modeling as per R6 methodology. Since stability studies are not required per TPL-001-4 for loss of entire generating plants or transmission substations – this creates a conflict in the currently proposed language.

FAC-013 Transfer Capability assessment requires the PC to develop a methodology for analysis, but there is no requirement to consider loss of "Generation at a single plant location or Transmission Facilities at a single station or substation location" and therefore this also creates a conflict in the currently proposed language.

The SOL SDT is considering adding new / revising existing definitions of IROLs and associated phenomena (such a System Instability, a re-work of Cascading, etc). If so, the impacts on the CIP standards would have to be re-visited. Southern is concerned that the timing of these proposed changes in CIP-002 should be postponed until the SOL SDT modifications to defined terms are finalized and can be more properly incorporated into CIP-002, Att 1 Criteria.

Southern also requests the SDT consider that Criteria 2.3 and the new 2.6 are now duplicative based on the proposed changes, and that the SDT should consider the following proposal:

{C}1. Criteria 2.3: Each generation Facility that its Planning Coordinator or Transmission Planner

designates, and informs the Generator Owner or Generator Operator, as necessary to

avoid an **Adverse Reliability Impact** in the planning horizon of more than one year.

{C}2. Adverse Reliability Impact: The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.

{C}3. Criteria 2.6 (SDT Proposed): Generation at a single plant location or Transmission Facilities at a single station or substation location identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer

Capability assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

Southern recommends the following changes to obtain consistency between Criteria 2.3 and Criteria 2.6 by modifying Criteria 2.3 and removing Criteria 2.6:

{C}· *Criteria 2.3 (Southern Proposed): Generation at a single plant location or Transmission Facilities at a single station or substation location that the Planning Coordinator or Transmission Planner designates, and informs the Generation Owner or Generator Operator, or Transmission Owner or Transmission Operator, as necessary to avoid Adverse Reliability Impact in the planning horizon of more than one year.*

{C}· *Criteria 2.6 (Southern Proposed): Removed and combined w. Criteria 2.3 as of CIP-002-6.*

Some supporting justification for the modification of Criteria 2.3 and the removal of Criterion 2.6 are:

{C}1. The time horizon for CIP-002-6 is “Operations Planning”, so Operational Planning Analysis, not “Near-Term Transmission Planning Horizon analysis”, is appropriate for any evaluation of potential Operating Horizon instability, Cascading, or uncontrolled separation;

{C}2. The consistent use of the NERC defined term Adverse Reliability Impact addresses the components of the previously used IROL definition, and consolidates two separate Criteria dealing with PC/TP studies and identification of critical Facilities for both Generation and Transmission;

{C}3. The consistent use of the NERC defined term Adverse Reliability Impact also properly scopes the PC/TP identification of critical Facilities to the Operations Planning horizon that results in subsequent evaluation of assets potentially containing BES Cyber Systems. It is not feasible to consider, and creates conflicts with existing Planned and Unplanned Change requirements, to have to potentially commission (or decommission) CIP assets based on the results of “Near-Term Planning Assessments”.

If Criteria 2.6 is to remain in the CIP-002-6 Standard, the wording should remain unchanged from the existing, approved langauge. The existing wording allows operating horizon IROLs to be evaluated using Operations Planning analysis, rather than requiring the use of Near-Term Transmission Planning Horizon analysis. Reliability Coordinators presently establish operating horizon IROLs to prevent instability, Cascading, and uncontrolled separation from occurring based on the present FAC-011-3 and FAC-014-2 standards, and they will continue to do so based on the revisions proposed for FAC-011-4 and FAC-014-3 in NERC Project 2015-09.

CIP-002-6 R1 is an Operations Planning Horizon requirement and the FAC-011 and FAC-014 standards provide methodology and criteria details that are pertinent to an Operations Planning evaluation. Only operating horizon IROLs should presently apply to Criteria 2.6. For example, compliance with present TPL-001-4 (and proposed TPL-001-5) standard causes any future instability, Cascading, or uncontrolled separation circumstances caused by Planning Events to be identified and mitigated before the Operations Planning Horizon begins. Therefore, through this mitigation, there should be minimal Planning Assessments or Transfer Capability assessments by Planning Coordinators or Transmission Planners that identify any Generation or Transmission Facilities as applicable to Criterion 2.6.

Southern Company is concerned that the use of term ‘instability’, within the context of Criterion 2.6, represents an untenable expansion of the scope for CIP-002-6. Our concerns rest on the belief that the proposed language in Criterion 2.6, if approved, could require many entities to reclassify substantial numbers of BES Cyber Systems to higher impact classifications when there has been no change in risk to BES reliability. The language provided in the GTB appears to have the intent of limiting the scope to Wide Area impacts, but unfortunately this is not reflected in the plain language in Criterion 2.6 or Criteria 2.9. This inconsistency between the GTB and Criterion could lead to confusion and inconsistent results. Southern suggests incorporating the consistent use of the term Adverse Reliability Impact to properly scope the Criterion requirements (See additional comments under question 2). This would be consistent with the scoping of CIP-014 that limits the scope of instability to within an Interconnection.

Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See MidAmerican Energy Company comments.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
The standard claims the Medium Impact Rating criteria mentioned in Attachment 1 provides a set of “bright-line” critieria that the Responsible Entity must use to identify the BES cyber systems in accordance with the impact on the BES. However, the proposed changes to Medium Impact Rating Criterion 2.6 seem to be far away from “bright-line.” Especially, use of the terms like “instances of instability,” “Cascading,” and “uncontrolled separation.” This is very dependent on each transmission planner’s criteria, methodology and threshold for the above items and could vary considerably even between the Planning Coordinator’s Assessment and the Transmission Planner’s Assessment. For example “instances of instability” may be limited one small generator of it may impact multiple generators in a region. Suggest the standard drafting team come up with more specific methodology in place of IROL or delete this Criterion.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	

Comment	
Exelon is concerned with the use of the term 'instability' within Criterion 2.6, inconsistent with how it is used in the GTB for Criterion 2.9. Use of this term should be limited to Wide Area impacts. More clarity is also needed on the timing related to Near-Term Transmission Planning Horizon, to avoid subjecting a Facility projected to be medium impact five years out to CIP compliance in year one. Consider adding language similar to that used within TPL-001-4, Requirement 2.7, which would help remove ambiguity.	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP Agrees with the proposed modification.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst agrees with the proposed modification.	
Likes 0	
Dislikes 0	
Response	
David Rivera - New York Power Authority - 3	
Answer	Yes
Document Name	
Comment	
This Requirement does not identify the information sharing mechanism from the Planning functions to the TOP/TO/GOP/GO. We understand that FAC-015 has this information sharing Requirement. We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion. We request clarification on whether the entire substation (or generator) is in scope OR specific elements in the substation (or generator).	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	

Comment	
This Requirement does not identify the information sharing mechanism from the Planning functions to the TOP/TO/GOP/GO. We understand that FAC-015 has this information sharing Requirement. We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion. We request clarification on whether the entire substation (or generator) is in scope OR specific elements in the substation (or generator).	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ	
Answer	Yes
Document Name	
Comment	
This Requirement does not identify the information sharing mechanism from the Planning functions to the TOP/TO/GOP/GO. We understand that FAC-015 has this information sharing Requirement. We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion. We request clarification on whether the entire substation (or generator) is in scope OR specific elements in the substation (or generator)	
Likes 0	
Dislikes 0	
Response	

Lana Smith - San Miguel Electric Cooperative, Inc. - 5 - Texas RE	
Answer	Yes
Document Name	
Comment	
SMEC suggest the SDT insert **Wide Area** impact into the requirement and in the supplemental material for Criterion 2.6 when referencing “instability, Cascading, or uncontrolled separation.”	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We request clarification on whether the entire substation (or generator) is in scope OR specific elements in the substation (or generator)	
Likes 0	
Dislikes 0	
Response	

Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
The Standard Drafting Team needs to address whether the proposed redlines in Projects 2016-02 and 2015-09 are meant to clarify existing practices for identifying BES assets, or are intended to modify current approaches, specifically with regard to identifying generation resources under CIP-002. The proposed redline changes in CIP-002 and CIP-014 limit the application of facility identification that may result in instances of instability, Cascading or uncontrolled separation to only Planning Coordinator's Planning Assessments of the near-term Planning Horizon and transfer assessments. This proposed change might be read to reduce the potential sources of information / analysis which entities use to today to make such identifications. Lastly, the Project 2016-02 Standard Drafting Team must coordinate with the Project 2015-09 Standard Drafting Team since these redlines appear not only for modifications to CIP-002 but also to CIP-014, and the requisite and primary technical expertise to understand IROLs is in the Project 2015-09 SDT.	
Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
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	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 1	Arkansas Electric Cooperative Corporation, 6, Walkup Bruce
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Heather Morgan - EDP Renewables North America LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	

AECI supports the comments provided by NRECA.

Likes 0	
Dislikes 0	

Response

2. Attachment 1, Criterion 2.9: Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.9? If not, please provide your rationale and an alternate proposal.

Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon believes that more clarity is needed in Criterion 2.9 to ensure limited impact RAS are not incorrectly identified as medium impact BES Cyber Systems. As demonstrated by the language in PRC-012-4, limited impact RAS should be classified as low impact.	
Likes 0	
Dislikes 0	
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Tri-State agrees with the comments submitted by Barry Lawson of NRECA. In addition, Tri-State suggest the new Criterion 2.9 should read, "Each Remedial Action Scheme (RAS) that operates BES Elements identified by the Planning Coordinator in accordance with PRC-012-2 R4.1, as not being limited impact RAS." If the drafting team adopts this revision, Criterion 3.5 should also be modified so it is clear that only limited impact RAS qualify as Low Impact.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See MidAmerican Energy Company comments.	
Likes 0	

Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment

Southern Company views the inclusion of the term “Wide Area” in the Guidelines and Technical basis, but its absence in the Att 1 Criteria 2.9 language, to be a significant variance. As proposed in the comments for Criteria 2.3 and Criteria 2.6 above, Southern recommends the consistent use of the term Adverse Reliability Impact as a replacement for the previously used IROL reference. We think the phrase “Wide Area” as used in the G&TB is commensurate with the use of the term Adverse Reliability Impact when it comes to properly scoping the potential impact of BES Cyber Systems used in a RAS.

Attachment 1 - *SoCo TP Proposed language:*

2.9. *Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent* ***Adverse Reliability Impact****. OR,*

2.9 *Each Remedial Action Scheme (RAS) where inadvertent operation or failure to operate could cause or contribute to instances of* ***Adverse Reliability Impact***.

Southern also feels a significant proposed change has been made to Criteria 2.9 that may not have been intended. With the new proposed language, all BES Cyber Systems associated with a RAS will be considered medium impact. This is a significant change from the current Criteria 2.9 where some RAS will be medium impact and others will be low impact (Att 1, Criteria 3.5). We understand that the basis for this revision is to remove references to IROLs, but we do not support making all RAS medium impact, whether intended or not. Southern requests that the SDT adjust the revisions for removing the IROL language such that the current medium and low impact categorization of each RAS remains unchanged.

The proposed language used in Criterion 2.9 does not appropriately align with PRC-012-2, Requirement 4.3.1, which states the following:

“For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.”

The footnote further states:

“A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.”

For this reason, Southern asks the SDT to provide more clarity in Criterion 2.9 to ensure limited impact RAS are not inappropriately identified as medium impact BES Cyber Systems. As clearly demonstrated by the language in PRC-012, limited impact RAS should be classified as low impact.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

Incorporating by reference the companies' response to Question 1, we recommend rationalizing "instability" with the NERC Glossary Term "System."

System: "A combination of generation, transmission, and distribution components."

The proposed revision:

"Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent **System** instability, Cascading, or uncontrolled separations."

This recommendation also aligns with the NERC Glossary Term, Cascading, "…loss of system elements…"; and uncontrolled separations.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

WAPA supports the comments of the NSRF, in particular: "consider rewording Criterion 2.9 to "Each Remedial Action Scheme (RAS) whose inadvertent operation or failure to operate could cause or contribute to instability, Cascading, or uncontrolled separation." [reference PRC-012-2, 4.1.3].

This approach would categorize all limited impact RASs and other qualifying RASs as low impact rating assets. In addition, this approach is more Brightline than the proposed approach. All RASs can be readily categorized based on the latest PRC-012-2 4.1 evaluations without the need for supplemental analysis"

Likes 0	
Dislikes 0	

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy believes that more clarity is needed in Criterion 2.9 to ensure limited impact RAS are not inappropriately identified as medium impact BES Cyber Systems. As clearly demonstrated by the language in PRC-012-4, limited impact RAS should be classified as low impact.	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Similar to our comments in response to Question 1, EEI is troubled by the proposed language in Criterion 2.9 largely due to the continued use of the unbounded term 'instability'. While we believe the SDT did not intend to include local events that would not impact BES reliability, clarifications provided in the Guideline and Technical Basis are insufficient given entities are bound to comply with the language within an approved Reliability Standard, not the GTB Moreover, the proposed language used in Criterion 2.9 does not appropriately align with PRC-012-2, Requirement 4.3.1, which states the following: *"For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."* *The footnote further states:* *A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."* *For this reason, EEI believes that more clarity is needed in Criterion 2.9 to ensure limited impact RAS are not inappropriately identified as medium impact BES Cyber Systems. As clearly demonstrated by the language in PRC-012-4, limited impact RAS should be classified as low impact.*	
Likes 0	
Dislikes 0	
Response	

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	

Comment	
ATC is concerned that the introduction of new terminology for ‘designed to prevent’ could be subjective and believes existing wording from PRC-012-2 Part 4.1.3 could be leveraged to align the standards and objectives to those defined concepts. For this reason, ATC requests SDT consideration of the following rewording of Criterion 2.9 to something like, “Each Remedial Action Scheme (RAS) whose inadvertent operation or failure to operate could cause or contribute to instability, Cascading, or uncontrolled separation.” [reference PRC-012-2, 4.1.3]. This approach would categorize all limited impact RASs and other qualifying RASs as low impact rating assets. In addition, this approach is more Brightline than the proposed approach. All RASs can be readily categorized based on the latest PRC-012-2 4.1 evaluations without the need for supplemental analysis.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
We disagree with the draft language where all BES Cyber Systems associated with a RAS will be medium impact. Categorization of RASs must align with PRC-012-2 R4.1. The PRC-012-4 R4.3.1 states, “4.1.3. For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.” The footnote states, “A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.” A limited RAS should not be identified as medium impact in criteria 2.9. Limited impact RAS should be low impact. Attachment 1 criteria 3.5 should be clarified to be limited impact RAS. Criteria 2.9 should be modified for clarity to include, “Limited RAS are excluded.” Insert Wide Area impact into the requirement to be consistent with the supplemental material when referencing “instability, Cascading, or uncontrolled separation.”	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	

Comment	
We disagree with the draft language where all BES Cyber Systems associated with a RAS will be medium impact. Categorization of RASs must align with PRC-012-2 R4.1. The PRC-012-4 R4.3.1 states, “4.1.3. For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.” The footnote states, “A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.” A limited RAS should not be identified as medium impact in criteria 2.9. Limited impact RAS should be low impact. Attachment 1 criteria 3.5 should be clarified to be limited impact RAS. Criteria 2.9 should be modified for clarity to include, “Limited RAS are excluded.” Insert Wide Area impact into the requirement to be consistent with the supplemental material when referencing “instability, Cascading, or uncontrolled separation.”	
Likes 0	
Dislikes 0	
Response	
Heather Morgan - EDP Renewables North America LLC - 5	
Answer	No
Document Name	
Comment	
The undefined term ‘instability’ could expand the scope of both medium and high impact cyber asset classification. Due to the lack of clarificaiton with respect to the tirm "instability", elements that are low impact could be viewed as medium impact without necessity. Criteria needs to be included on who or what defines if a RAS is designed to prevent instabiliity.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NERC Standards Review Forum (NSRF).	
Likes 0	

Dislikes 0	

Response

Barry Lawson - National Rural Electric Cooperative Association - 4	
Answer	No
Document Name	

Comment

NRECA believes a significant proposed change has been made to 2.9 that may not have been intended. With the new language, all BES Cyber Systems associated with a RAS will be medium impact. This is a significant change from the current 2.9 where some RAS will be medium impact and others will be low impact (Attachment 1, Criterion 3.5). We understand that the basis for this revision is to remove references to IROLs, but we do not support making all RAS medium impact, whether intended or not. NRECA requests that the SDT adjust the revisions for removing the IROL language such that the current medium and low impact categorization of each RAS remains unchanged.

In addition, on page 26, the 4th bullet under the “Managing Constraints” section (that begins on page 25), this bullet should be deleted since it refers to IROLs.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment

NV Energy disagrees with the current draft language, as it reads, where all BES Cyber Systems associated with a RAS will be identified as a medium impact asset.

Categorization of RASs must align with PRC-012-2 R4.1. The PRC-012-2 R4.3.1 states, “4.1.3. For limited impact RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.”

The footnote states, “A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.” A limited RAS should not be identified as medium impact in criteria 2.9. Limited impact RAS should be low impact. Attachment 1 criteria 3.5 should be clarified to be limited impact RAS. Criteria 2.9 should be modified for clarity to include, “Limited RAS are excluded.”

Insert Wide Area impact into the requirement to be consistent with the supplemental material when referencing “instability, Cascading, or uncontrolled separation.”

Likes 0	

Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	

AZPS is not in agreement with the proposed modifications to CIP-002-6 Attachment 1, Criterion 2.9. The language in CIP-002-6 Attachment 1, Criterion 2.9 and the Guidelines and Technical Basis of Criterion 2.9 are not in alignment because IROLs, by their nature, produce Wide Area impacts and this Wide Area designation is clear in the technical basis. That there is not an indication or designation of Wide Area impacts in Criterion 2.9 could result in local area RASs that do not affect the BES being identified pursuant to this Criterion. As stated above, local, non-BES impacts are not in alignment with the Wide Area designation in the technical basis nor the Wide Are impacts that are one of the hallmarks of an IROL. To ensure this alignment and properly retain the intent of Criterion 2.9, APS proposes the following language for CIP-002-6 Attachment 1, Criterion 2.9 to align it with the technical basis.

2.9 Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent Wide Area impacts such as instability, Cascading, or uncontrolled separation.

Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	No
Document Name	
Comment	

LES supports the following NSRF comments:

The NSRF recommends the deletion of Criterion 2.9 after the PRC-012-2 standard becomes effective. PRC-012-2 R3 requires any reliability issues with new or functionally modified RASs to be resolved prior to the RAS being placed in service and PRC-012-2 4.1 obligates limited impact RASs and ‘other’ RASs to meet stringent reliability performance requirements, which are sufficient to exempt them from being CIP-002-6 medium impact rating candidates. This approach would categorize all RASs as low impact rating assets due to the stringent limitations of the potential BES reliability impacts on PRC-012 compliant RASs. In addition, this approach is a more Brightline criteria than the proposed approach.

With the new language, all BES Cyber Systems associated with a RAS will be medium impact. This is a significant change from the current 2.9 where some RAS will be medium impact and others will be low impact (Attachment 1, Criterion 3.5).

If Criterion 2.9 is not removed, consider rewording Criterion 2.9 to “Each Remedial Action Scheme (RAS) whose inadvertent operation or failure to operate could cause or contribute to instability, Cascading, or uncontrolled separation.” [reference PRC-012-2, 4.1.3].

This approach would categorize all limited impact RASs and other qualifying RASs as low impact rating assets. In addition, this approach is more Brightline than the proposed approach. All RASs can be readily categorized based on the latest PRC-012-2 4.1 evaluations without the need for supplemental analysis	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The NSRF recommends the deletion of Criterion 2.9 after the PRC-012-2 standard becomes effective. PRC-012-2 R3 requires any reliability issues with new or functionally modified RASs to be resolved prior to the RAS being placed in service and PRC-012-2 4.1 obligates limited impact RASs and ‘other’ RASs to meet stringent reliability performance requirements, which are sufficient to exempt them from being CIP-002-6 medium impact rating candidates. This approach would categorize all RASs as low impact rating assets due to the stringent limitations of the potential BES reliability impacts on PRC-012 compliant RASs. In addition, this approach is a more Brightline criteria than the proposed approach. With the new language, all BES Cyber Systems associated with a RAS will be medium impact. This is a significant change from the current 2.9 where some RAS will be medium impact and others will be low impact (Attachment 1, Criterion 3.5). If Criterion 2.9 is not removed, consider rewording Criterion 2.9 to “Each Remedial Action Scheme (RAS) whose inadvertent operation or failure to operate could cause or contribute to instability, Cascading, or uncontrolled separation.” [reference PRC-012-2, 4.1.3]. This approach would categorize all limited impact RASs and other qualifying RASs as low impact rating assets. In addition, this approach is more Brightline than the proposed approach. All RASs can be readily categorized based on the latest PRC-012-2 4.1 evaluations without the need for supplemental analysis	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
The undefined term ‘instability’ could be interpreted to include strictly local events that could impact a single bus. The current use of ‘instability’ could be interpreted to include every RAS that interacts with the BES rather than the previous limitation to those RASs that impacted an IROL.	

Dominion Energy recommends that the term ‘instability’ be eliminated from any of the Requirements and Attachments in CIP-002-6.	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We generally agree with the proposed changes. However, NERC should modify Criterion 2.9 to make clear that RAS used for protection as opposed to "instability, Cascading or uncontrolled separation" is excluded from the determination of the medium impact rating.	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
GSOC agrees with that IROLs established by the RC is not an appropriate qualifier in the determination of Facilities that require cyber-related hardening as these limits may be related to be highly specific, temporary, or sudden onset types of events determined in operational and real-time horizons. The identification of these Facilities are more appropriately based on long-term planning studies.	

Further, the alternate wording embedded in the Attachment 1 is an appropriate substitution in response to the proposed retirement of FAC-010-2. This wording incorporates the severe System impacts currently associated with IROLs so the intent of the criterion is preserved.

GSOC do recommend the SDT consider incorporating a qualifier for the term " instability" in the proposed criterion to make clear that the criterion is referring to System impacts. A potential wording modification could be as follows:

Each Remedial Action Scheme (RAS) that operates BES Elements and is designed to prevent instability, Cascading, or uncontrolled separation on the System (or system).

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ

Answer	Yes
Document Name	

Comment

Request explanation of why changing from the older CIP (IROL) phrasing to the newer FAC (instability, cascading or uncontrolled separation) phrasing

Likes 0	
Dislikes 0	

Response

David Rivera - New York Power Authority - 3

Answer	Yes
Document Name	

Comment

Request explanation of why changing from the older CIP (IROL) phrasing to the newer FAC (instability, cascading or uncontrolled separation) phrasing.

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment	
ReliabilityFirst agrees with the proposed modification.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the proposed modifications in CIP-002-6, Criterion 2.9	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 1	Arkansas Electric Cooperative Corporation, 6, Walkup Bruce
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5 - Texas RE	
Answer	
Document Name	
Comment	
SMEC agrees with NRECA comments. A significant proposed change has been made to 2.9 that may not have been intended. With the new language, all BES Cyber Systems associated with a RAS will be medium impact. This is a significant change from the current 2.9 where some RAS will be medium impact and others will be low impact (Attachment 1, Criterion 3.5). We understand that the basis for this revision is to remove references to IROLs, but we do not support making all RAS medium impact, whether intended or not. NRECA requests that the SDT adjust the revisions for removing the IROL language such that the current medium and low impact categorization of each RAS remains unchanged. In addition, on page 26, the 4th bullet under the “Managing Constraints” section (that begins on page 25), this bullet should be deleted since it refers to IROLs. SMEC also suggests the SDT insert **Wide Area** impact into the requirement to be consistent with the supplemental material for Criterion 2.9 when referencing “instability, Cascading, or uncontrolled separation".	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	

3. Attachment 1, Criterion 2.12: No changes have been added from the previous ballot. Do you agree with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12? If not, please provide your rationale and an alternate proposal.

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
It is Idaho Power Company's understanding that there are ongoing discussions within one or more Standards Drafting Teams (SDT) about the definition of a Control Center. It seems plausible to wait until those discussions are settled to make a change to this criterion rather than to try to make a change now and then potentially make another one down the road when those SDT discussions are settled.	
Likes 0	
Dislikes 0	
Response	

Larry Watt - Lakeland Electric - 1	
Answer	No
Document Name	
Comment	
Comments: The current definition in 2.12 does not differentiate between the type of Transmission Line that is used in criteria 2.5 and 2.8. Should generator interconnection facilities be included in the count or not? Also, in the case of tie lines, Entity A may own the substation when Entity B has a breaker/relays, etc. The loop through breaker is owned by Entity B. Entity B officially is the TO/TOP; contractually Entity A has supervisory trip control due to proximity to Entity A's equipment and will only exercise that to protect and safeguard human life from possible injury or death, or, in an emergency to protect a part of Entity A's power system from damage. While both Entites are monitoring the line (along with the RC), Entity B is the Control Authority for that line/breaker and is including that line it its own calculation of 2.12 if Entity B is not already governed by 1.1 – 1.4. We believe that Entity A would be duplicating the count of the line if it is included under 2.12. Please clarify. We recommend the clarification that lines identified/classified under Criterion 2.8 should not be included in the calculation of Criterion 2.12 Control Centers.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	

Comment	
As submitted during the previous comment period for this standard, the proposed modifications could lead to Transmission Owners (TO) performing functional obligations of Transmission Operators that currently have medium impact BES Cyber Systems because of 2.12; to become low impact. For example: • The use of the term "and" means that a TO that monitors but **does not control** is no longer classified as a medium BES Cyber Asset. • A TO that monitors and controls a substation (A) that has three 345 kV lines and two 138 kV lines. Its "aggregated weighted value" would be 1300+1300+1300+250+250=4,400. This TO also monitors and controls another substation (B) with one 345 kV lines and one 138 kV lines. Its "aggregated weighted value" would be 1300+250=1,550. 4,400 (A)+1,550 (B) =5,950, which is less than 6,000. Therefore, even though this TO may meet the definition of Control Center, the Control Center's BES Cyber Systems would now be low impact even though the substation itself would have medium impact BES Cyber Systems (medium impact criteria 2.5). Texas RE is concerned this will have a negative impact on reliability since less assets would be protected under the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
We do not agree with the 6000 point threshold in isolation. Rather, it should be determined in connection with connected assets. For example, if a control center controls a medium impacted rated substation then the control center should be designated as medium regardless of the weighted value per line total.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	

See MidAmerican Energy Company comments.	
Likes 0	
Dislikes 0	
Response	
Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst agrees with the proposed modification.	

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5	
Answer	Yes
Document Name	
Comment	
There is a discrepancy in word case for Criterion 2.11 and 2.13 between the requirement and the supplemental material. The word "Interconnection" is a NERC defined term (page 17 here), but is not consistently capitalized and I believe it should be. The outcome will not change our compliance requirements or responsibilities, but should make it more consistent across the document.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Rivera - New York Power Authority - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 1	Arkansas Electric Cooperative Corporation, 6, Walkup Bruce
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Barry Lawson - National Rural Electric Cooperative Association - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Heather Morgan - EDP Renewables North America LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	

4. Guidelines and Technical Basis: Do you agree with the proposed modifications to Criterion 2.6 of the Guidelines and Technical Basis section of the CIP-002-6 standard?	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
Please add language to the GTB that addresses our concerns as provided through our comments for Question 1.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
"Instances of Instability, Cascading or Uncontrolled Separation" is a very vaguely defined criteria and is far away from the "bright-line" intent of Attachment 1 in this standard, please see our comments provided to Question 1.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See MidAmerican Energy Company comments.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	
No. Please see the comments for question 1.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	
Comment	
It would be helpful to add language to clarify how results from any new studies are shared with impacted asset owners.	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	
Comment	
The PC and TP are not identified in the Applicability Section, nor are the PC/TP involved in the Operations Planning Horizon.	
Likes 0	
Dislikes 0	
Response	

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy recommends that the SDT provide greater clarity on the following concerns:

1. It is unclear whether the SDT is suggesting that additional studies be conducted for every generation and Transmission facility.
2. It is unclear whether the SDT's intended to create a new requirements for the Planning Authority and Transmission Planners.
3. It is unclear whether there are any obligations to ensure that the results from any new studies are appropriately shared with impacted asset owners.

In addition to the comments above, we ask the SDT to add language to the Guidelines and Technical Basis that addresses our concerns as provided through our comments for Question 1.

Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

We agree with the proposed changes except as noted in our response to 3 above. The 6000 threshold for qualifying as a medium impact control center should not be made in isolation of the rating of relevant assets. For example, a control center that operates a medium impact station should be rated a medium impact, irrespective of the weighted value per line total.

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	

ITC Supports the comments filed by the NSRF:

Please see comments for Question 1.

Likes 0	
Dislikes 0	

Response

Randy MacDonald - NB Power Corporation - 1

Answer	No
Document Name	

Comment

Does “Facilities lost or degraded” correlate with those events in table 1 of TPL-001-4? If not please point to the PC/TP Planning Assessment requirements that would identify those Facilities under section 2.6.

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

EEI asks the SDT to provide greater clarity on the following concerns:

1. *It is unclear whether the SDT is suggesting that studies be conducted for every generation and Transmission facility.*
2. *It is unclear whether the SDT’s intended to create a new requirements for the Planning Authority and Transmission Planners.*
3. *It is unclear whether there are any obligations to ensure that the results from any new studies are appropriately shared with impacted asset owners.*

In addition to the comments above, we ask the SDT to add language to the GTB that addresses our concerns as provided through our comments for Question 1.

Likes 0	
Dislikes 0	

Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Same comments as for Question # 1.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The Guidelines and Technical Basis (actually Supplemental Material) for Criterion 2.6 should be changed to address comments on Question 1.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ	
Answer	No
Document Name	
Comment	
We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion. Suggest different wording since instability may be based instability - “Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena such as instability or voltage collapse” . . . should not use the word being defined in the definition We understand that the CIP-002 experts expects someone else to provide this operations assessment list. Why is this not explicitly stated? Suggested revised language:	

Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena (e.g., voltage collapse, angular instability, transient voltage dip criteria violation).

The Standard and GTB should explicitly reference FAC-015 Requirement 4, since the Transmission Planner that performs the FAC-015 assessment needs to tell the CIP-002 Asset Classification SME which assets, if lost, would result in instability, Cascading, or uncontrolled separation. Similarly, FAC-015 should include some kind of reference back to CIP-002-6, not necessarily in Requirement 4, but perhaps in the GTB for FAC-015.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer	No
Document Name	

Comment

The Guidelines and Technical Basis (actually Supplemental Material) for Criterion 2.6 should be changed to address comments on Question 1.

Likes 0	
Dislikes 0	

Response

Heather Morgan - EDP Renewables North America LLC - 5

Answer	No
Document Name	

Comment

The undefined term ‘instability’ could expand the scope of both medium and high impact cyber asset classification. Due to the lack of clarificaiton with respect to the tirm "instability", elements that are low impact could be viewed as medium impact without necessity. Criteria needs to be included on who or what defines if a RAS is designed to prevent instabiliity.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	No
Document Name	
Comment	
The GTB may need to be revised if comments in question 1 and question 3 are addressed.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy asks the SDT to add language to the GTB that addresses our concerns as provided through our comments for Question 1.	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	

Comment	
AZPS is not in agreement with the proposed modifications to the Guidelines and Technical Basis for CIP-002-6 Attachment 1, Criterion 2.6. As described in its comments in response to Question 1 and for the same reasons, the proposed modifications to the Guidelines and Technical Basis for CIP-002-6 Attachment 1, Criterion 2.6 revise and expand the underlying obligation of Responsible Entities, which is beyond the intent of the associated SAR.	
Likes 0	
Dislikes 0	
Response	

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	No
Document Name	
Comment	
Please see our comments for Question 1.	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
The Guidelines and Technical Basis does not appear to say much more than the criterion itself. More information would be helpful to provide guidance in the implementation of the criterion and the proposed change.	
Likes 0	
Dislikes 0	
Response	

David Rivera - New York Power Authority - 3	
Answer	No
Document Name	
Comment	

We suggest this criterion update explicitly reference FAC-015 planning assessment and that FAC-015 planning assessment explicitly reference this criterion.

Suggest different wording since instability may be based instability - “Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena such as instability or voltage collapse” . . . should not use the word being defined in the definition.

We understand that the CIP-002 experts expects someone else to provide this operations assessment list. Why is this not explicitly stated?

Suggested revised language:

Instances of instability, Cascading, or uncontrolled separation may be based on dynamic System phenomena (e.g., voltage collapse, angular instability, transient voltage dip criteria violation).

The Standard and GTB should explicitly reference FAC-015 Requirement 4, since the Transmission Planner that performs the FAC-015 assessment needs to tell the CIP-002 Asset Classification SME which assets, if lost, would result in instability, Cascading, or uncontrolled separation. Similarly, FAC-015 should include some kind of reference back to CIP-002-6, not necessarily in Requirement 4, but perhaps in the GTB for FAC-015.

Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Please see our comments for Question 1.

Likes 0	
Dislikes 0	
Response	

Leanna Lamatrice - AEP - 3	
Answer	No

Document Name	
Comment	
Additional text should be added to make it clear that the RC, TP, or PC is expected to notify affected Responsible Entities.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
It is unclear if the studies in criterion 2.6 are required to be performed for every generation and Transmission facility and if the intent of the modification to 2.6 could create a new requirement of the Planning Authoirty and Transmission Planners. It is also unclear if there is a current requirement for the results of the studies to be shared with the studied Facility owners or if the intenet is to create a new requirement. The potential communication gap created by this lack of clarity could result in Facility owners considering the criterion as not applicable to their Facilities.	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	

Comment	
The Standard Drafting Team needs to address whether the proposed redlines in Projects 2016-02 and 2015-09 are meant to clarify existing practices for identifying BES assets, or are intended to modify current approaches, specifically with regard to identifying generation resources under CIP-002. The proposed redline changes in CIP-002 and CIP-014 limit the application of facility identification that may result in instances of instability, Cascading or uncontrolled separation to only Planning Coordinator's Planning Assessments of the near-term Planning Horizon and transfer assessments. This proposed change might be read to reduce the potential sources of information / analysis which entities use to today to make such identifications. Lastly, the Project 2016-02 Standard Drafting Team must coordinate with the Project 2015-09 Standard Drafting Team since these redlines appear not only for modifications to CIP-002 but also to CIP-014, and the requisite and primary technical expertise to understand IROLs is in the Project 2015-09 SDT.	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5 - Texas RE	
Answer	Yes
Document Name	
Comment	
SMEC suggests the SDT insert **Wide Area** impact into supplemental material for Criterion 2.6 when referencing "instability, Cascading, or uncontrolled separation".	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
As written, It is already clear that the CIP-002 experts are not the one proceeding the operations assessment list. It should be the transmission planner or planning coordinator.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
The term Transfer Capability assessment is not a defined term in the NERC Glossary, so the word “assessment” should not be capitalized as it is in the GT&B section and other places in the document.	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst agrees with the proposed modification.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Russell Martin II - Salt River Project - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
SRP agrees with the proposed modifications to Criterion 2.6 of the Guidelines and Technical Basis section of the CIP-002-6 standard.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard	

Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

James Anderson - CMS Energy - Consumers Energy Company - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	

5. Guidelines and Technical Basis: Do you agree with the proposed modifications to Criterion 2.9 of the Guidelines and Technical Basis section of the CIP-002-6 standard?

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

The GTB document appears to have the intent of limiting the scope of the criterion to only Wide Area impacts, which is not reflected in the word of the actual criterion in Appendix 1. This inconsistency between the GTB and the words of the criterion could lead to confusion and inconsistent results.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Please see our comments for Question 2.

Likes 0	
Dislikes 0	

Response

David Rivera - New York Power Authority - 3

Answer	No
Document Name	

Comment

Is criterion 2.9 associated with any other NERC Standards / Requirements like 2.6? If yes, what other NERC Standards / Requirements?

Criterion 2.9 in the GTB includes a “Wide Area” qualifier that is not present in the version of criterion 2.9 in Attachment 1 – Impact Rating Criteria. Recommend removing the term “Wide Area” from the GTB.

Likes 0	

Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	No
Document Name	
Comment	
Please see our comments for Question 2.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The Supplemental Material should be changed to address comments on Question 2.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Heather Morgan - EDP Renewables North America LLC - 5	
Answer	No
Document Name	
Comment	
The undefined term ‘instability’ could expand the scope of both medium and high impact cyber asset classification. Due to the lack of clarificaiton with respect to the tirm "instability", elements that are low impact could be viewed as medium impact without necessity. Criteria needs to be included on who or what defines if a RAS is designed to prevent instabiliity.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
The Supplemental Material should be changed to address comments on Question 2.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
Criteria 2.9 seems more general and do not have any connection with the criteria 2.6. As the focus on the BES elements that if lost or degraded can cause instability, Cascading or uncontrolled sepration.We propose the following text: “2.9 Each remedial Action Scheme (RAS) that operates BES elements that if lost or degraded can cause instability, Cascading or uncontrolled separation”.	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ	
Answer	No
Document Name	
Comment	
Is criterion 2.9 associated with any other NERC Standards / Requirements like 2.6? If yes, what other NERC Standards / Requirements? Criterion 2.9 in the GTB includes a “Wide Area” qualifier that is not present in the version of criterion 2.9 in Attachment 1 – Impact Rating Criteria. Recommend removing the term “Wide Area” from the GTB.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The Supplemental Material should be changed to address comments on Question 2.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Same comments for Question # 2.	

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

EEI believes the language provided in the GTB appears to have the intent of limiting the scope of the Criterion 2.9 to only Wide Area impacts, unfortunately this is not reflected in the plan language in Criterion 2.9. This inconsistency between the GTB and Criterion 2.9 could lead to confusion and inconsistent results.

Likes 0	
Dislikes 0	

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy notes that the language provided in the the Guidelines and Technical Basis may be interpreted as limiting the scope of the Criterion 2.9 to only Wide Area impacts, which is not reflected in the plan language in Criterion 2.9. This inconsistency between the Guidelines and Technical Basis and Criterion 2.9 could lead to confusion and inconsistent results.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

The language may create an unintended compliance issue. Specifically, it identifies a result, “Wide Area impacts,” that are not mentioned in Criterion 2.9. Including the reference establishes a compliance threshold. Since G&TB documents are not enforceable, establishing a compliance threshold is inconsistent with the NERC Rules of Procedure.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
No. Please see the comments for question 1.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See MidAmerican Energy Company comments.	
Likes 0	
Dislikes 0	
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	

The guidlines and technical basis should be changed to align with the new approach for Criterion 2.9.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
Please address along with comments in Question 2. Inconsistency between the GTB and Criterion 2.9 could lead to confusion and inconsistent results.	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the proposed modifications to Criterion 2.9 of the Guidelines and Technical Basis section of the CIP-002-6 standard.	
Likes 0	

Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst agrees with the proposed modification.	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
AZPS is in agreement with the proposed modifications to the Guidelines and Technical Basis for CIP-002-6 Attachment 1, Criterion 2.9. As described in its comments in response to Question 2, AZPS recommends that Attachment 1, Criterion 2.9 is modified in order to align with Criterion 2.9 of the Guidelines and Technical Basis for CIP-002-6 Attachment 1, Criterion 2.9.	
Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We generally agree with the proposed changes. However, NERC should modify Criterion 2.9 to make clear that RAS used for protection as opposed to "instability, Cascading or uncontrolled separation" is to be excluded from the determination of the medium impact rating.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leanna Lamatrice - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
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	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	

Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	

6. Implementation Plan: The SDT proposes an Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is fifteen (15) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon is concerned that if the intent of the proposed modifications to criterion 2.6 and 2.9 is to expand the scope to include every generator and transmission substation as medium impact, as well as requiring limited impact RAS to be reclassified as medium impact BES Cyber Systems the resulting impact to the industry would be exceedingly large and well beyond the 15 months provide in the proposed implementation plan. Therefore, without changes to address our concerns we cannot support the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See MidAmerican Energy Company comments.	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
EEI is concerned that if the intent of the proposed modifications to criterion 2.6 and 2.9 is to expand the scope to include every generator and transmission substation as medium impact, as well as requiring limited impact RAS to be reclassified as medium impact BES Cyber Systems the	

resulting impact to the industry would be exceedingly large and well beyond the 15 months provide in the proposed implementation plan. Therefore, without changes to address our concerns we cannot support the proposed Implementation Plan.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

As proposed by the SDT, Criterion 2.9 may cause some entities to reclassify BES Cyber Assets impact levels. This would require more time for the budgeting and procurement processes to purchase additional equipment. Therefore 24 calendar months after the effective date is recommended to cover both timelines included in the implementation plan periods for unplanned changes of 12 and 24 months. Also, these changes should not be effective before PRC-012-2.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer	No
Document Name	

Comment

As proposed by the SDT, Criterion 2.9 may cause some entities to reclassify BES Cyber Assets impact levels. This would require more time for the budgeting and procurement processes to purchase additional equipment. Therefore 24 calendar months after the effective date is recommended to cover both timelines included in the implementation plan periods for unplanned changes of 12 and 24 months. Also, these changes should not be effective before PRC-012-2.

Likes 0	
Dislikes 0	

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	No

Document Name	
Comment	

To ensure a successful implementation of the revised standard, we recommend that the revised standard become effective the first day of the first calendar quarter that is **twenty-four (24) calendar months** after the effective date of the applicable governmental authority's order approving the standard.

Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	No
Document Name	
Comment	

Our comments are peripherally related to the Implementation Plan but also extend to the Section 5 included in CIP-002-6.We are concerned with the Near-Term Planning Assessment language and the "Section 5 Planned and Unplanned Changes" implementation table. The timeframe might be sufficient for a substation to come into compliance but it is unlikely that a new medium impact generating plant designated under the proposed 2.6 would be able to meet the compliance obligations. If an Entity that owns low impact assets containing BES Cyber Systems, the Entity will need significantly more time to develop a full-blown CIP program if the are brought into the CIP compliance obligation by the PA or TOP.

Scenario of Unplanned Change - New medium impact BES Cyber System where the Responsible Entity has not previously identified a medium or high impact BES Cyber System.

Implementation Period - 36 calendar months from the date of notification or detection of the Unplanned Change.

Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

As proposed by the SDT, Criterion 2.9 may cause some entities to reclassify BES Cyber Assets impact levels. This would require more time for the budgeting and procurement processes to purchase additional equipment. Therefore, 24 calendar months after the effective date is recommended to cover both timelines included in the implementation plan periods for unplanned changes of 12 and 24 months. Also, NV Energy believes that these changes should not be effective prior to the effective date of PRC-012-2.

Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
While AZPS appreciates that the SDT is now proposing a 15 month implementation timeline, it continues to remain concerned that a longer timeline is necessary. Accordingly, AZPS reiterates its previous comments that the implementation time period be 24 calendar months from the date of notification or detection of the unplanned changes regardless of whether or not the Entity has previously identified a low, medium, or high impact BES Cyber System associated with that same BES asset type as the effort required would involve the design and implementation or technology, procurement, and contracting efforts, which could easily exceed 15 months.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
A longer implementation time period is needed. Instead of 15 months after the effective date of the applicable governmental authority's order approving the standard, the revised standard should become effective the first day of the first calendary quarter that is twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard. This is to allow additional needed time for entities to prepare, plan, budget, procure, and hire additional labor resources to meet all the applicable reliability standards in becoming a Medium or High Impact entity from an existing Low-Impact entity. Cost estimates from consultants range anywhere from $100,000.00 for consultant fees only, to $1 million or more depending on computer hardware, facility hardening, and security software. This is especially burdensome for smaller entities, such as NCPA, who need more time, money, and approvals from it's governing board to make sure we have the funds and resources to properly prepare for and meet the new CIP reliability requirements.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Answer	No
Document Name	
Comment	
Reclamation recommends CIP-002-6 become effective no earlier than 18 months after the applicable governmental entity's order approving the standard to allow entities flexibility to determine the appropriate implementation.	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	
To ensure a successful implementation of the revised standard, we recommend that the revised standard become effective the first day of the first calendar quarter that is **twenty-four (24) calendar months** after the effective date of the applicable governmental authority's order approving the standard.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No
Document Name	
Comment	
To ensure a successful implementation of the revised standard, we recommend that the revised standard become effective the first day of the first calendar quarter that is **twenty-four (24) calendar months** after the effective date of the applicable governmental authority's order approving the standard.	
Likes 0	
Dislikes 0	
Response	

Leanna Lamatrice - AEP - 3	
Answer	No
Document Name	
Comment	
The 15 months provided in the Implementation Plan for establishing the effective date is reasonable, however AEP believes that the allowance for an Unplanned Change (within the Standard itself) is not sufficient. As currently proposed, it does not provide sufficient time to accomplish all the physical changes necessary to move from compliance for an asset containing low impact BES Cyber Systems to one where all the BES Cyber Systems are instantly categorized as medium. Instead, 24 months should be permissible whether or not the Responsible Entity has previously identified a medium or high impact BES Cyber System associated with that same BES asset type. AEP recommends the Unplanned Changes Section be updated to address this and any other similar set of circumstances. Please note that AEP's negative ballots are primarily driven by our concerns expressed in this response to Question #6.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
If the intent of the proposed modifications to criterion 2.6 and 2.9 is to expand the scope to include every generator and transmission substation as medium impact, at a minmum, then a phased implementation plan over a minimum period of 7-10 years could be necessary to budget and physically upgrade all of the applicable low impact assets to meet the requirements for a medium impact assest.	
Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Before approval and enforcement a couple of changes need to be made. Everywhere they refer to MOD-024 they need to change it to MOD-025. MOD-024 was never approved. MOD-025 contains both MOD-024 and 025.	
Likes 1	Nebraska Public Power District, 3, Eddleman Tony

Dislikes 0	

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment

CenterPoint Energy agrees with the Standard Drafting Team's proposed Implementation Plan to make the revised standard effective the first day of the first calendar quarter that is fifteen (15) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

However, CenterPoint Energy believes the implementation timeline for planned changes resulting in a higher categorization as proposed in CIP-002-6 is not consistent with the concept in the current CIP Version 5/6 implementation plan. Page 4, paragraph 3 of the "Implementation Plan for Version 5 CIP Cyber Security Standards" states that for planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements "**on the update of the identification and categorization of the affected BES Cyber System**," not "upon the commission date of the planned change" as proposed in CIP-002-6.

CenterPoint Energy recommends removing the phrase "or a change in categorization for an existing BES Cyber System" from the second paragraph in section 6 to keep it focused on planned changes resulting in a new BES Cyber System and adding the following paragraph for planned changes resulting in a higher categorization:

"For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets."

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
As submitted during the previous comment period for this standard, Texas RE inquires as to why the section regarding planned and unplanned changes was removed from the implementation plan. Since they no longer reside in one of the enforceable parts of the standard, this will cause confusion upon implementation. Texas RE recommends keeping this section in the implementation plan. Texas RE also noticed that PCAs were removed from the graphic on page 7, but is still in the list of Cyber Assets on page 9.	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst agrees with the proposed modification.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the Implementation Plan	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy MacDonald - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Heather Morgan - EDP Renewables North America LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6, Group Name LES	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
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	
David Rivera - New York Power Authority - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	

Document Name	
Comment	
We neither agree nor disagree. Note, however, that 15 months may impact the ability to implement RAS additions.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	

7. The SDT believes proposed modifications in CIP-002-6 provide entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Section 6 Under New medium impact BES Cyber System associated with a BES asset type where the Responsible Entity has not previously identified a medium or high impact BES Cyber System associated with that same BES asset type – 24 calendar months from the date of notification or detection of the Unplanned Change.

24 Months is not enough time to take a Low Impact Facility and bring it into compliance as a Medium especially for a generation facility. Budgets, new BES System design, equipment delivery, installation of equipment and patching, writing procedures, policy and processes, creating evidence and documentation are required to go from a Low Impact to a Medium Impact System and remain in compliance. This needs to be 48 Months to be completed cost effectively.

Likes 1	Nebraska Public Power District, 3, Eddleman Tony
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

The apparent intent to expand the scope of medium and high impact Cyber Assets does not appear to be a cost effective use of resources for the reliability benefit to be gained.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The NSRF request that Section 6 “Background” is removed completely or moved to the Guideline and Technical Basis section. The entire Guideline and Technical Basis section should be removed from the Standard as it may be interpreted as how to meet the Compliance obligations of the Requirements. FERC Order 693 section 253 states, “The most critical element of a Reliability Standard is the Requirements. As NERC explains, “the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA.” This information should reside outside the Standard as a NERC Compliance Guidance document.

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer	No
Document Name	

Comment

NO, WE DO NOT ARGEE, as the language of the “Planned Changes” treats High, Medium and Low Impact BES Cyber Systems/Assets all the same. Specifically, when it comes to Low Impact System/Assets, the changes mandate less flexibility and would require immediate, “upon commissioning” compliance and rather than being documented and discovered during the once every 15 calendar months assessment, necessitate real-time tracking of all modification projects that might add to or change Low Impact BES Cyber Systems/Assets.

Additionally:

Much of the language dates back to the Implementation Plan of CIP-002 rev 2 and the document, **Implementation Plan for Newly Identified Critical Cyber Assets** when the focus was on much more critical and essential cyber assets that could potentially, significantly impact the reliability of the BES. Applying these same implementation/new milestones (and thus immediately “upon commissioning”) and requirements to Low Impact BES Cyber Systems/Assets in not appropriate to the risk.

- To put things in perspective, Low Impact BES Cyber Systems/Assets typically would have previously been considered “non-critical” cyber assets under the earlier CIP versions/requirements and thus required zero protections, ever. Although, this may have resulted previously in some gap in protection, it is with this background that newly identified Low Impact BES Cyber Systems/Assets needs to be viewed.

- As such, a compliance implementation milestone table needs to be again utilized for not only Unplanned Changes, but Planned Changes as well.

- Additionally, keeping in line with the once every 15 calendar months assessment of cyber systems/assets, Planned additions of Low Impact BES Cyber Systems/Assets should not require individual real-time tracking (that would be necessitated with compliance upon commissioning) and instead should be discovered during the once every 15 calendar months assessment and then compliant some time thereafter, following the assessment. …12 months seems a reasonable duration for this.

- Further, in contrast and to put things in better perspective, allowing 12 months for a High-Impact BES Cyber System/Asset (Or 24 months if a new asset type) for an Unplanned Change and yet requiring a Low Impact BES Cyber System/Asset as part of a “planned” modification to be compliant upon commissioning makes little sense, especially in a risk-based environment.

- Planned additions of new (or recently re-categorized) Low Impact systems/assets should have an implementation table commensurate with their low-to-minimal-to-possibly virtually non-existent impact.

Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	

NO, WE DO NOT ARGEE, as the language of the “Planned Changes” treats High, Medium and Low Impact BES Cyber Systems/Assets all the same. Specifically, when it comes to Low Impact System/Assets, the changes mandate less flexibility and would require immediate, “upon commissioning” compliance and rather than being documented and discovered during the once every 15 calendar months assessment, necessitate real-time tracking of all modification projects that might add to or change Low Impact BES Cyber Systems/Assets.

Additionally:

- Much of the language dates back to the Implementation Plan of CIP-002 rev 2 and the document, **Implementation Plan for Newly Identified Critical Cyber Assets** when the focus was on much more critical and essential cyber assets that could potentially, significantly impact the reliability of the BES. Applying these same implementation/new milestones (and thus immediately “upon commissioning”) and requirements to Low Impact BES Cyber Systems/Assets in not appropriate to the risk.

- To put things in perspective, Low Impact BES Cyber Systems/Assets typically would have previously been considered “non-critical” cyber assets under the earlier CIP versions/requirements and thus required zero protections, ever. Although, this may have resulted previously in some gap in protection, it is with this background that newly identified Low Impact BES Cyber Systems/Assets needs to be viewed.

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- Further, in contrast and to put things in better perspective, allowing 12 months for a High-Impact BES Cyber System/Asset (Or 24 months if a new asset type) for an Unplanned Change and yet requiring a Low Impact BES Cyber System/Asset as part of a “planned” modification to be compliant upon commissioning makes little sense, especially in a risk-based environment.

- Planned additions of new (or recently re-categorized) Low Impact systems/assets should have an implementation table commensurate with their low-to-minimal-to-possibly virtually non-existent impact.

Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick	
Answer	No
Document Name	
Comment	
We are concerned that the language in Criteria 2.6 could cause new generation assets to be identified as needing to meet CIP-002-6 medium/high impact criteria for a short time frame until a Corrective Action Plan could be implemented. Additionally, current generation that is not medium could possibly become medium as other generation is retired if the retirement caused a change in IROLs. Could the language be modified to be a "newly identified issue that will not be obviated within 3 years"?	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Prior to proposing additional modifications, Reclamation recommends each SDT take additional time to effectively define the scope of each Standard Authorization Request to minimize the costs associated with the planning and adjustments required to achieve compliance with frequently changing requirements. This will provide entities with economical relief by allowing technical compliance with current standards. Reclamation also recommends the SDT use existing NERC Glossary of Terms or follow procedures for adding new terms to the NERC Glossary of Terms. For example, Planned and Unplanned Changes are identified within the standard and are not listed within the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	

There is no reason to change the existing two year time period in preparing to meet the new Medium or High impact CIP reliability requirements. The new requirement to start the clock running when a contract with a customer is signed to provide control center operation services to manage their generation facilities doesn't make sense if the net real power from the additional 100 MW nameplate capacity only results in 50 MW of net real power during the following summer months. It is possible that all the work, time, and money spent to go from Low to Medium impact based on a signed contract would be wasted if the net real power never reaches the 1500 MW threshold.

It would be better to keep the existing two year transition period which starts when the net real power reaches the 1500 MW threshold, regardless, when the control center operation service contract gets signed.

Likes 0	
Dislikes 0	

Response

Eric Ruskamp - Lincoln Electric System - 6, Group Name LES

Answer	No
Document Name	

Comment

LES supports the following NSRF comments:

The NSRF request that Section 6 “Background” is removed completely or moved to the Guideline and Technical Basis section. The entire Guideline and Technical Basis section should be removed from the Standard as it may be interpreted as how to meet the Compliance obligations of the Requirements. FERC Order 693 section 253 states, “The most critical element of a Reliability Standard is the Requirements. As NERC explains, “the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA.” This information should reside outside the Standard as a NERC Compliance Guidance document.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy does not believe that at this time, due to necessary changes for Criterion 2.6 and 2.9, are able to agree. It is good the SDT is trying to retain identical language between CIP-002-6 Attachment 1 Criterion 2.6 and CIP-014-3 Applicability 4.1.1.3. Each ballot needs to be conditional on the other ballot being approved It would be clearer if these identical changes are balloted at the same time to keep them in synch. As it is now, the separate ballots could result in changes for one standard while the other could be approved as is or with different language. If the language does not remain identical, we cannot approve either one.

Additional Comments: • Unless there are proposed NERC glossary terms for Planned and Unplanned Changes, these terms should not be capitalized. • Page 28 of the Supplemental Material references MOD-024, but MOD-024 never became effective. It was skipped for MOD-025. This reference should be changed to MOD-025.	
Likes 0	
Dislikes 0	
Response	
Larry Watt - Lakeland Electric - 1	
Answer	No
Document Name	
Comment	
We are concerned that the new language in Criteria 2.6 will cause new assets (big iron) to be identified as needing to meet CIP-002-6 medium impact criteria for a short time frame until a Corrective Action Plan could be implemented. This does not seem prudent to support from a ratemaking perspective, especially as generation is retired. Could the language be modified to be a “newly identified issue that will not be obviated within 3 years”? Otherwise, an Entity will spend considerable time and money to develop a CIP program that might not be required depending on the timeframe the Corrective Action is completed.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	No

Document Name	
Comment	

NO, WE DO NOT ARGEE, as the language of the "Planned Changes" treats High, Medium and Low Impact BES Cyber Systems/Assets all the same. Specifically, when it comes to Low Impact System/Assets, the changes mandate less flexibility and would require immediate, "upon commissioning" compliance and rather than being documented and discovered during the once every 15 calendar months assessment, necessitate real-time tracking of all modification projects that might add to or change Low Impact BES Cyber Systems/Assets.

Additionally:

Much of the language dates back to the Implementation Plan of CIP-002 rev 2 and the document, **Implementation Plan for Newly Identified Critical Cyber Assets** when the focus was on much more critical and essential cyber assets that could potentially, significantly impact the reliability of the BES. Applying these same implementation/new milestones (and thus immediately "upon commissioning") and requirements to Low Impact BES Cyber Systems/Assets in not appropriate to the risk.

- To put things in perspective, Low Impact BES Cyber Systems/Assets typically would have previously been considered "non-critical" cyber assets under the earlier CIP versions/requirements and thus required zero protections, ever. Although, this may have resulted previously in some gap in protection, it is with this background that newly identified Low Impact BES Cyber Systems/Assets needs to be viewed.
- As such, a compliance implementation milestone table needs to be again utilized for not only Unplanned Changes, but Planned Changes as well.
- Additionally, keeping in line with the once every 15 calendar months assessment of cyber systems/assets, Planned additions of Low Impact BES Cyber Systems/Assets should not require individual real-time tracking (that would be necessitated with compliance upon commissioning) and instead should be discovered during the once every 15 calendar months assessment and then compliant some time thereafter, following the assessment. …12 months seems a reasonable duration for this.
- Further, in contrast and to put things in better perspective, allowing 12 months for a High-Impact BES Cyber System/Asset (Or 24 months if a new asset type) for an Unplanned Change and yet requiring a Low Impact BES Cyber System/Asset as part of a "planned" modification to be compliant upon commissioning makes little sense, especially in a risk-based environment.
- Planned additions of new (or recently re-categorized) Low Impact systems/assets should have an implementation table commensurate with their low-to-minimal-to-possibly virtually non-existent impact.

Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer	No
Document Name	
Comment	

Not at this time because changes for Criterion 2.6 and 2.9 are needed. It is good the SDT is trying to retain identical language between CIP-002-6 Attachment 1 Criterion 2.6 and CIP-014-3 Applicability 4.1.1.3. Each ballot needs to be conditional on the other ballot being approved It would be clearer if these identical changes are balloted at the same time to keep them in synch. As it is now, the separate ballots could result in changes for one standard while the other could be approved as is or with different language. If the language does not remain identical, we cannot approve either one.

Additional notes: Unless there are proposed NERC glossary terms for Planned and Unplanned Changes, these terms should not be capitalized. Page 28 of the Supplemental Material references MOD-024, but MOD-024 never became effective. It was skipped for MOD-025. This reference should be changed to MOD-025.

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

: Not at this time because changes for Criterion 2.6 and 2.9 are needed. It is good the SDT is trying to retain identical language between CIP-002-6 Attachment 1 Criterion 2.6 and CIP-014-3 Applicability 4.1.1.3. Each ballot needs to be conditional on the other ballot being approved It would be clearer if these identical changes are balloted at the same time to keep them in synch. As it is now, the separate ballots could result in changes for one standard while the other could be approved as is or with different language. If the language does not remain identical, we cannot approve either one.

Additional notes: Unless there are proposed NERC glossary terms for Planned and Unplanned Changes, these terms should not be capitalized. Page 28 of the Supplemental Material references MOD-024, but MOD-024 never became effective. It was skipped for MOD-025. This reference should be changed to MOD-025.

Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

If the proposed wording for Criterion 2.9 remains unchanged, it could cause Registered Entities to incur additional administrative and financial burden. ATC believes a more cost effective approach would be to align the language in Criterion 2.9 with PRC-012-2 Part 4.1.3 so Registered Entities may use those RAS evaluations as an input to CIP-002. This approach offers a more holistic and consistent method for determining impact.

Likes 0	
Dislikes 0	

Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
At this time, EEI cannot support the SDT's belief that the current version of CIP-006-2 provides entities with flexibility to meet the reliability objectives intended for this Reliability Standard in a cost-effective manner. This is largely due to issues and concerned reflected in our comments associated with Criterion 2.6 and 2.9. *Additional EEI Comments include the following:* 1. *The term 'Planned and Unplanned Changes' should not be capitalized given this is not a defined term as found in the NERC Glossary of Terms.* 2. *On page 29 (Redline version) of the Supplemental Material, a reference is made to MOD-024, however, MOD-024 was never approved. It was skipped in favor of MOD-025. This reference should be changed to MOD-025.*	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
Incorporating our response to Question 1, without establishing bounds to the word "instability," the expected result potentially shifts BES Cyber Systems from low to medium and medium impact systems to high. Such a shifting of impacts is likely without improving BES reliability. If such is the case, the companies believe that the cost to implement Requirements without improving reliability is inconsistent with a cost-effective approach.	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See MidAmerican Energy Company comments.	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
At this time, Exelon cannot support the SDT's belief that the current version of CIP-006-2 provides entities with flexibility to meet the reliability objectives intended for this Reliability Standard in a cost-effective manner. This is largely due to issues and concerned reflected in our comments associated with Criterion 2.6 and 2.9. Additional comments include the following: 1. The term 'Planned and Unplanned Changes' should not be capitalized given this is not a defined term as found in the NERC Glossary of Terms. 2. On page 29 (Redline version) of the Supplemental Material, a reference is made to MOD-024, however, MOD-024 was never approved. It was skipped in favor of MOD-025. This reference should be changed to MOD-025.	
Likes 0	
Dislikes 0	
Response	

Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees	
Likes 0	

Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst agrees with the proposed modification.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
We thank the SDT for allowing us to provide comments on these standards.	
Likes 0	
Dislikes 0	
Response	
Vivian Vo - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
AZPS agrees that the proposed modification provide entities with flexibility to meet the reliability objectives, provided the implementation period is reasonable (i.e., 24 months). Otherwise it may require entities to expand significant resources to meet timeframes that may be unnecessarily short.	
Likes 0	

Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company also supports MRO's comments under Project 2015-09 Establish and Communicate System Operating Limits, which include:

The changes to CIP-002-6 criterion 2.6 and 2.9 do not add clarity. Unfortunately, the proposed changes to criterion 2.9 would bring in most SPS/RAS in the country because these systems are typically designed to avoid instability or a cascading outage scenario. Similarly, the proposed changes to criterion 2.6 substantially expands the scope of analysis. The current CIP-002-5.1 criterion 2.6 language is very clear and narrow because it limits the evaluation to those Facilities that have been shown to impact a large area of the system (i.e. what it means to be an IROL). With the proposed changes, many more Facilities will need to be evaluated for instability, but the end result will still be very few Facilities on the list (and those that make it on the list probably have an SPS/RAS to mitigate the concern). This appears to be an unneeded expansion of the criterion whereas the current language is precise. The SDT should keep in mind that IROLs will still exist under the proposed FAC standard revisions for the operating horizon and, therefore, no change is needed to R2.6 or R2.9.

Southern also recommends that the SDT consider the following:

The new 2.6/2.9 criteria are for TPL studies from TPL standards that only apply to a TP and PC. The criteria for those studies and the results of them are being placed in a CIP-002 Standard that does not even apply to TP or PC - it applies to RC/BA/TO/TOP/GO/GOP. These entities are required to have a process that considers each of the criteria in Attachment 1. If a TOP/GOP entity read the 2.6/2.9 criteria from a purely TOP/GOP perspective, you'll see that they can't prove those criteria. The only thing they could prove is whether or not they were officially notified by a TP/PC that they had such a facility, but there is nothing to obligate a TP/PC to officially notify them.

Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	

Entergy has a concern regarding Medium Impact Rating Criterion 2.3. This Criterion calls for designating and informing respective Generator Owner or Generator Operator, each generation facility that its Planning Coordinator or Transmission Planner determines as necessary to avoid an Adverse

Reliability Impact in the planning horizon of more than one year. The concern here is there is no clarity in the roles of Planning Coordinator versus the Transmission Planner. The guidelines and technical basis section spells (page 29 of proposed clean version of the standard) out that in cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation. However, in cases where there is a Planning coordinator, the criterion or guideline does not spell out who is responsible. Secondly, this Criterion is far away from the "bright-line" intent of Attachment 1 Criteria in this standard. The Responsible entities have to perform several system studies to address the requirements to meet this criterion. Suggest the Standards Drafting Team consider spelling out what an entity should do incase they are registered with a Planning Coordinator.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Val Ridad - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Julie Severino - FirstEnergy - FirstEnergy Corporation - 1, Group Name FirstEnergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Van Brimer - Southwest Power Pool, Inc. (RTO) - 2 - MRO	
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	
Heather Morgan - EDP Renewables North America LLC - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicholas Lauriat - Network and Security Technologies - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and HQ	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Goldberg - ISO New England, Inc. - 2 - NPCC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Sanders - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amber Orr - Public Utility District No. 1 of Pend Oreille County - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ryan Walter - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	CIP-002-6 Comments.docx
Comment	
Additional comments: see attachment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	

Document Name	
Comment	
AECI supports the comments provided by NRECA.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	
Document Name	
Comment	
ABSTAIN with no comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
We concur that the modification provides some flexibility; however, there is no information/evidence to support any statement on cost-effectiveness and would recommend that NERC delete "in a cost effective manner."	
Likes 0	
Dislikes 0	
Response	
Eli Rivera - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	

No response.

Likes 0	
Dislikes 0	

Response