Consideration of Comments

Project Name:	2016-02 Modifications to CIP Standards | CIP-002-6 (Draft 4)
Comment Period Start Date:	11/1/2019
Comment Period End Date:	12/16/2019
Associated Ballots:	2016-02 Modifications to CIP Standards CIP-002-6 AB 4 ST

There were 52 sets of responses, including comments from approximately 119 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

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

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

Questions

1. Attachment 1, Criterion 2.12: Modifications were made to the Attachment 1, Criterion 2.12 to provide clarity. 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.

2. Based on comments received from industry, the SDT reverted the Planned and Unplanned Changes section back to current state by removing it from the Effective Date section of CIP-002-6 and moving the existing language from the CIP-002-5.1a Implementation Plan into the CIP-002-6 Implementation Plan (with only updates to version information). Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal.

3. 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.

4. If you have additional comments on the proposed CIP-002-6 that you have not provided in response to the questions above, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Eric Jensen	Arizona Electric Power Cooperative	1	WECC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					Joseph Smith	Prairie Power , Inc.	1,3	SERC
					Carl Behnke	Southern Maryland Electric Cooperative	3	RF
					Tara Lightner	Sunflower Electric Power Cooperative	1	MRO
					Susan Sosbe	Wabash Valley Power Association	3	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	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
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Solutions International Inc.		
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Mike Forte	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Ashmeet Kaur	Con Ed - Consolidated Edison	5	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	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 2.12: Modifications were made to the Attachment 1, Criterion 2.12 to provide clarity. 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*****.**

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
The changes add clairification, however, the extremely long sentances are awkward and will cause confusion in application of the approved standards.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment. The SDT agrees that the sentences in Criterion 2.12 are long. However, in response to previous comment periods and issues raised, much was needed to clearly convey the intent of the criterion.	
James Baldwin - Eugene Water and Electric Board - 1,3 – WECC	
Answer	No
Document Name	
Comment	
EWEB believes that criterion 2.12 places undue hardship on utilities that have a robust system. EWEB’s system is designed to provide reliable load; however, due to the new, ambiguous aggregate rating, EWEB would be classified as a Medium Impact entity. The new criterion places undue hardships on smaller utilities that do not have the resources available to efficiently comply with the CIP Medium Impact Standards.	

Instead of the SDT pulling more entities into the Medium Impact Category, EWEB suggests that the CIP Low requirements be enhanced to establish greater Critical Infrastructure Protection. The difference between the CIP Low and CIP Medium Requirements is drastic, closing this gap would enhance security without over-burdening smaller entities that pose little to no threat to the BES.

An alternative to the aggregate weight of number of lines a Transmission Owner has could be the total distance of lines owned in kV categories.

Likes 0	
Dislikes 0	

Response: Thank you for your comment. The current enforceable version of CIP-002 does not allow BES Cyber Systems associated with a Control Center that performs the functional obligation of the Transmission Operator (TOP) to be categorized as low impact. The revisions to Criterion 2.12 set a floor for medium impact BES Cyber Systems at Control Centers that perform the functional obligation of the TOP, which allows Control Centers of lower risk to categorize their BES Cyber Systems as low impact. During the development process, the SDT discussed using line miles to help determine categorization but received feedback that line miles do not necessarily identify the criticality of the BES Elements.

Anthony Jablonski - ReliabilityFirst – 10

Answer	No
Document Name	

Comment

The “aggregate weighted value” concept of Criterion 2.12 is acceptable. However, Criterion 2.12 uses the phrase, “used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines” while Criterion 1.3 uses the different phrase, “used to perform the functional obligations of the Transmission Operator.” The two criteria should use the same language in order to prevent gaps in applicability between the two criteria.

Likes 0	
Dislikes 0	

Response: Thank you for your comment. The SDT developed the proposed language in Criterion 2.12 to emphasize the real-time aspects associated with the functional tasks performed at Control Centers, regardless of the entity's functional registration. The SDT contends that the proposed language is suitable for medium impact BES Cyber Systems that do not meet the high impact categorization detailed in Criterion 1.3.

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

As previously submitted, Texas RE is concerned the proposed modifications could lead to Transmission Owners (TO) performing functional obligations of Transmission Operators (TOP) or just TOP that currently have medium impact BES Cyber Systems because of 2.12; to become low impact.

- TO's performing functional obligations of TOP's and TOP Control Centers operating BES Transmission Lines less than 200 kV will go from having medium impact BES Cyber Systems to low impact BES Cyber Systems if the BES Transmission Lines do not have an "aggregate weighted value" exceeding 6000 according to the table in 2.12.
- Texas RE is concerned this will have a negative impact on reliability since less BES assets and BES Cyber Systems would be protected under the proposed revisions and become low impact.
  - There are no baselining, vulnerability assessment, ports and services, security patching, malicious code prevention, etc… Requirements for assets that contain low impact BES Cyber Systems.

Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comment. NERC has conducted a study where no additional identifiable risks were shown, and the Regional Entities were provided a chance to review the results.

Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) – 3	
Answer	No
Document Name	
Comment	
Similar to Criteria 2.5, Criteria 2.12 should only count lines connected to substations by three or more BES transmission lines. As written, the criteria overestimates the impact of small distribution substations that have a transmission line looped through the substation rather than just tapping the transmission line. As an example, consider a 115 kV transmission line connecting two major substations. Connected to this transmission line are five small unit substations serving load. Under the SDT proposal, if local distribution substations are tapped off of the line, the total weighted value would be 250. If the line is looped through each distribution substation, the line would instead have a weighted value of 1500. The looped through line typically has much better reliability, so weighting it six times worse seems inconsistent with improved reliability. A previous Considerations of Comments stated that the value of 6000 was based on NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index. https://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf" However, the SRI does not actually address lines less than 200 kV. The SRI was written in 2011, based on TADS data available at the time. TADS did not include complete reliability information on lines less than 200 kV until 2014. Lines below 200 kV typically configured differently than lines above 200 kV, with lower voltage lines often directly serving load. The SRI equation includes terms for both lost transmission lines and for lost load. Since lower voltage lines are much more likely than higher voltage lines to directly serve load, extrapolating data from higher voltages will incorrectly categorize risk.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment. The SDT contends that the 6000 aggregate weighted value is appropriate and should include BES Transmission Lines below 200 kV. Additionally, the SDT addressed multiple-point (or multiple-tap) lines on page 33 of the CIP-002-6 supplemental material. Entities should be cognizant of the BES definition when applying this criterion.	
Spencer Tacke - Modesto Irrigation District – 4	
Answer	No

Document Name	
Comment	

In Section 2.12 , the phrase "...BES Transmission Lines with a..." should be revised to "...BES Transmission Lines and any other transmission lines operated at 60 kV and above with a...".

Likes 0	
Dislikes 0	

Response: Thank you for your comment. The SDT asserts that the table accurately identifies the weighted values for applicable BES Transmission Lines. Transmission Lines operated at a voltage less than 100 kV do not contribute to the aggregate weighted value.

Marty Hostler - Northern California Power Agency - 5

Answer	No
Document Name	
Comment	

I don't believe the standard was unclear before. I believe NERC, FERC, and Regional Entities were over reaching and should have been more reasonable and less overreaching. For instance:

New IRC 2.12 does not need to say **BES** Transmission lines or **Monitored and Controlled**. CIP-002-5.1a Page 2 Applicability Section 4.2.2 already says “All BES Facilities” it does not say non-BES facilities! Further, the GTB (CIP-002-5.1a GTB page 18) already mentions both Control and Monitor have to occur for a generator's or transmission line’s capability to be included in an IRC 2.11 or 2.12 evaluation.

I believe this is all being done because FERC incorrectly produced section 3 page 10 of https://ferc.gov/legal/staff-reports/2017/10-06-17-CIP-audits-report.pdf. FERC’s report says “For example, Criteria 2.11 requires categorization as Medium Impact of all Control Centers or backup Control Centers, not already categorized as High Impact, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. To determine whether a generation Control Center or back-up Control Center meets the 1500 MW threshold, the MW capacity of both BES generation and non-BES generation are considered. During audit fieldwork, staff found that some entities were only considering BES generation in applying Criteria 2.11, and therefore excluding all “non-BES generation” in their calculations. Foot note 9.”

Footnote 9 on Page 10 says "CIP-002-5.1a Attachment 1 does not define, or differentiate between, the terms "BES Generation," and "Non-BES Generation." Why would a GOP perform functional obligations of a GOP for a non-BES Generator? Non-registered entities that run generation don't need to! You don't have a CFR for a non-BES unit! There are no NERC obligations for a non-BES Unit! In my view FERC's footnote 9 is misleading: CIP-002-5.1a GTB page 17 clearly says: While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this **applicability scoping section**. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and **represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply**. **The IRCs are all in Attachment 1**, thus only BES Generator and Lines are to be considered for IRC 2.11 and 2.12!). Consequently, there is no need to consider non-BES generation since Items in Attachment 1 pertain to BES Facilities only. Additionally, FERC and NERC still have not answered my questions raised during drafting team phone/webinar meetings "What Generator or Transmission Operator Services does a GOP/TOP provide a non-BES generator/transmission line/substation?" Why would a GOP/TOP provide said unnecessary services when entities that are not NERC registered who own and run generators and transmission lines don't need to provide GOP/TOP services to the very same/similar non-BES assets? It is unfair to require GOP/TOPs to incur extra NERC Compliance costs for their Control Centers due to non-BES assets capability inclusion. NERC rules clear state "A reliability standard shall not give any market participant an unfair competitive advantage". Making GOPs/TOPs pay Control Center compliance costs for non-BES assets they operate is unfair as non-GOPs that own and run the same/similar units do not have to pay extra NERC cost for non-BES assets' they control and monitor from a central location(s). It ironic that NERC recently had another Project recently up for Ballot "Moving Technical Rational Sections" out of standards. Why? NERC/FERC are already ignoring the GTB and the applicability sections too? Waste of money and more confusion; have to reference several documents to comply with a single standard.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment. The Project 2016-02 Modification to CIP Standards Drafting Team developed the revisions to criterion 2.12 based on feedback from industry stakeholders that participated in the NERC CIP V5 Transition Advisory Group. The group of stakeholders identified ambiguity as it relates to entities that perform the functional obligation of the Transmission Operator. Previously, BES Cyber Systems associated with TO and TOP Control Centers that were not high impact had to at least be categorized as	

medium impact. There was no threshold below which these systems could fall to be categorized as low impact. Criterion 2.12 was revised so TO/TOP Control Centers that did have BES Cyber Systems of truly lower risk could fall below the medium impact threshold and be considered low impact. The table included in the SDT's proposed revision excludes Transmission Lines operated below 100 kV in accordance with the Bulk Electric System definition. The SDT thanks you for your comment regarding criterion 2.11, however the project 2016-02 SDT is not authorized to revise Criterion 2.11 in this project.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We agree with the drafting team, but we believe that Criterion 2.12 should be expanded to include any Control Center that operates a Medium Impact substation should be considered Medium Impact BES Cyber System (BCS).	
Likes 0	
Dislikes 0	

Response: Thank you for your comment. The SDT asserts that Criterion 1.3 accurately categorizes BES Cyber Systems at Control Centers that perform the functional obligations of the Transmission Operator for substations that contain medium impact BES Cyber Systems. The BES Cyber Systems in the example provided would be categorized as high impact BES Cyber Systems.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees with and supports the proposed modification in CIP-002-6 Attachment 1, Criterion 2.12.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment.	
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., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Westar Energy and Kansas City Power & Light support Edison Electric Institute’s response.	
Likes 0	
Dislikes 0	

Response: Please see the SDTs response to Westar Energy and Kansas City Power & Light support Edison Electric Institute's.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the proposed modification and appreciates the establishment of a bright line criteria between Low and Medium Impact Control Centers. The proposed change provides Registered Entities clarity which will help ensure that they have properly and consistently classified their BES facilities and assets.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment.	
Masuncha Bussey - Duke Energy - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Duke Energy generally agrees with the proposed modifications in CIP-002-6 Attachment 1, Criterion 2.12.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment.	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson	

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees with and supports the proposed modification in CIP-002-6 Attachment 1, Criterion 2.12.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment.	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

See EEI comments.	
Likes 0	
Dislikes 0	
Response: Please see the SDTs response to EEI.	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
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	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
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	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tim Womack - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
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	

Barry Lawson - National Rural Electric Cooperative Association - 4	
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	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch	
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	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
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	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF	
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	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pam Feuerstein - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

2. ***Based on comments received from industry, the SDT reverted the Planned and Unplanned Changes section back to current state by removing it from the Effective Date section of CIP-002-6 and moving the existing language from the CIP-002-5.1a Implementation Plan into the CIP-002-6 Implementation Plan (with only updates to version information). Do you agree with the proposed modification? If no, please provide your rationale and an alternate proposal*****.**

Marty Hostler - Northern California Power Agency - 5

Answer	No
Document Name	

Comment

Planned an unplanned language was never in the SAR and never should have been debated. And never should be. NERC/FERC was trying to take a GOP emphirical operations based data IRC 2.11 and change it to an unproven theoritically based criteria (Planned Changes). Totally unreasonable over regulation attempts.

Please I praise the STD for reverting back to the old implementation plan. But it was changed a little bit or word order changes. Why couldn't language be really reverted back to current state" ?

Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comment. The implementation plan was modified to reflect the CIP-002-5.1 implementation plan, with the addition of an example unplanned change.

Lana Smith - San Miguel Electric Cooperative, Inc. – 5

Answer	No
Document Name	

Comment

San Miguel agrees with comments submitted by NRECA.

Likes 0	
Dislikes 0	

Response: Please see the SDT's response to NRECA.

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

Answer	No
Document Name	

Comment

AECI supports comments filed by NRECA as such:

NRECA has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the "Planned Changes" section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the "Initial Performance of Periodic Requirements" section appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011. Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, NRECA recommends that the "Initial Performance of Periodic Requirements" section be revised to state:

"After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement."

Additionally, NRECA believes further clarification and guidance is needed to ensure consistent application of "Planned" and "Unplanned" changes, especially as it relates to who made the change(s) and if this impacted any adjacent or other facilities not included in the direct scope of the planned project. NRECA recommends that the SDT examine how this can be clarified in the standard, Supplemental Material, or Guidelines and Technical Basis.

Likes 0	
Dislikes 0	

Response: Please see the SDT's response to NRECA.

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio	
Answer	No
Document Name	
Comment	
NCEMC supports NRECA's Comments	
Likes 0	
Dislikes 0	
Response: Please see the SDT's response to NRECA.	

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

NRECA has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the "Planned Changes" section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the "Initial Performance of Periodic Requirements" section appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011. Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, NRECA recommends that the "Initial Performance of Periodic Requirements" section be revised to state:

"After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement."

Additionally, NRECA believes further clarification and guidance is needed to ensure consistent application of "Planned" and "Unplanned" changes, especially as it relates to who made the change(s) and if this impacted any adjacent or other facilities not included in the direct scope of the planned project. NRECA recommends that the SDT examine how this can be clarified in the standard, Supplemental Material, or Guidelines and Technical Basis.	
Likes 0	
Dislikes 0	
Response: The language in the planned changes section refers to the initial performance section of the CIP Version 5 Implementation Plan. In reverting to the previous language based on comments, the standard drafting team copied the language from that plan for convenience, noting that, "The planned and unplanned change provisions in the Implementation Plan associated with CIP-002- 5 shall apply to CIP-002-6. The Implementation Plan associated with CIP-002-5 provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard)." As such, the language in the CIP-002-6 Implementation Plan is a reproduction of version5 with clarifying changes in the Planned and Unplanned Changes section that point back to the CIP-002-5 Implementation Plan. Due to the Planned and Unplanned Changes being outside the scope of our Standards Authorization Request (SAR), a new SAR will be developed and submitted to NERC for a future project. These comments for that future project will be preserved as part of our project for reference**.**	
Andrea Barclay - Georgia System Operations Corporation - 4	
Answer	No
Document Name	
Comment	
GSOC has identified a potential gap in the language intended to address initial performance of periodic requirements. The language in the planned changes section of the implementation plan refers to all CIP Reliability Standards. However, the current language in the initial performance of certain periodic requirements appears to address only CIP-002-6 and does not address periodic requirements contained in CIP-003-CIP-011. Accordingly, responsible entity obligations relative to periodic requirements contained in CIP-003-CIP-011 are unclear. To facilitate a clear understanding of responsible entity obligations relative to other periodic requirements, GSOC recommends that the initial performance of certain periodic requirements be revised to state:	

After a cyber asset has been categorized under CIP-002-6, Requirement R1, responsible entities shall initially comply with any applicable periodic requirements in CIP Reliability Standards in accordance with the periodicity specified in the applicable requirement.

Likes 0	
Dislikes 0	

Response:
The language in the planned changes section refers to the initial performance section of the CIP Version 5 Implementation Plan. In reverting to the previous language based on comments, the standard drafting team copied the language from that plan for convenience, noting that, "The planned and unplanned change provisions in the Implementation Plan associated with CIP-002- 5 shall apply to CIP-002-6. The Implementation Plan associated with CIP-002-5 provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard)." As such, the language in the CIP-002-6 Implementation Plan is a reproduction of version5 with clarifying changes in the Planned and Unplanned Changes section that point back to the CIP-002-5 Implementation Plan.

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

We understand future revisions CIP-002 are currently being planned to address this, but would like to offer our comments pertaining to the subject as addressed in this revision. We prefer the draft version CIP-002-6 from 06/03/2019 where the proposed planned and unplanned language was made into subsections of the Effective Dates section. We feel that making this change gave entities a stronger legal basis for determining compliance due dates and operational definitions for newly identified BES Cyber Systems when planned or unplanned changes occur. The examples in the planned changes section contradict what the definition paragraph states for planned changes -

"Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the responsible entity **and** subsequently identified through the annual assessment under CIP-002-6, Requirement R2."

The “and” in the statement above seems to remove the requirement to have the BES Cyber System complaint prior to the date that the system can impact the Bulk Electric System. This would imply that there is a task to assess the new BES Cyber System’s compliance to the CIP standards before the required 15 month R2 review. This seems to create risk to the BES, considering that the BES Cyber System could be in operation for a period of time where it may or may not have all of the CIP controls applied to it.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comments. A more comprehensive look at the Planned and Unplanned Changes is outside the scope of our Standards Authorization Request (SAR). A new SAR will be developed and submitted to NERC for a future project. These comments for that future project will be preserved as part of our project for reference.	
Clay Walker - Cleco Corporation - 1,3,5,6 – SERC	
Answer	Yes
Document Name	
Comment	
See EEI comments.	
Likes 0	
Dislikes 0	
Response: Please see the SDT’s response to EEI.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	

: We understand future revisions CIP-002 are currently being planned to address this, but would like to offer our comments pertaining to the subject as addressed in this revision. We prefer the draft version CIP-002-6 from 06/03/2019 where the proposed planned and unplanned language was made into subsections of the Effective Dates section. We feel that making this change gave entities a stronger legal basis for determining compliance due dates and operational definitions for newly identified BES Cyber Systems when planned or unplanned changes occur. The proposed language for planned and unplanned changes in the current implementation planned removed the rigor to ensure that BES Cyber Systems that can impact the Bulk Electric System are compliant to the CIP Standards within the timeframes specified for planned or unplanned changes. The examples in the planned changes section contradict what the definition paragraph states for planned changes -

"Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the responsible entity **and** subsequently identified through the annual assessment under CIP-002-6, Requirement R2."

The "and" in the statement above seems to remove the requirement to have the BES Cyber System complaint prior to the date that the system can impact the Bulk Electric System. This would imply that there is a task to assess the new BES Cyber System's compliance to the CIP standards before the required 15 month R2 review. This seems to create risk to the BES, considering that the BES Cyber System could be in operation for a period of time where it may or may not have all of the CIP controls applied to it.

Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comments. Due to the Planned and Unplanned Changes being outside the scope of our Standards Authorization Request (SAR). A new SAR will be developed and submitted to NERC for a future project. These comments for that future project will be preserved as part of our project for reference.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI supports the proposed modification.

Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment.	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson	
Answer	Yes
Document Name	
Comment	
PG&E appreciates the SDT reverting the Planned and Unplanned Changes back to the original CIP-005-5 conditions until an appropriate SAR can be proposed to address the conditions raised in the July 2019 CIP-002-6 comment and ballot.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment.	
Masuncha Bussey - Duke Energy - 1,3,5,6 – SERC	
Answer	Yes
Document Name	
Comment	
Duke Energy generally agrees with the proposed modifications. However, the speed in which solar sites are being built does not allow sufficient time to build physical security controls without delaying solar connection to the grid. Duke would like to see an implementation plan for newly build generation which allows the registered entity a specified amount of time (6 months) to complete compliance tasks and documentation.	

Duke Energy would like the unplanned change definition to include purchases of new generation as well. The registered entity knows the purchase is taking place, but the plant will need to be included in the Duke program after the purchase date.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment. This modification is outside the scope of our SAR. The team will consider this comment for the upcoming SAR to be submitted. These comments for that future project will be preserved as part of our project for reference.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern agrees with reverting this wording back to the "current state". Moving this proposed change to a separate SAR will give the SDT and the industry much needed time to fully explore additional options and appropriately weigh any compliance risk associated with the change.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

We agree with the change, however it should be clear that the implementation schedule is applicable to any of the unplanned change type listed on the table of CIP-002-6 on page 3 and is enforceable going forward, not just during transition from CIP-002-5.1a to CIP-002-6.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment. The SDT agrees that the unplanned changes section is enforceable until CIP-002-6 is superseded or retired.	
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., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Westar Energy and Kansas City Power & Light support Edison Electric Institute's response.	
Likes 0	
Dislikes 0	
Response: Please see the SDT's response to EEI's comment.	
Daniel Gacek - Exelon – 1	
Answer	Yes
Document Name	

Comment	
Exelon supports the proposed modification.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment.	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
The existing language from the CIP-002-5.1a Implementation Plan moved into the CIP-002-6 Implementation Plan provides shorter implementation periods than the Planned and Unplanned Changes section stricken from CIP-002-6 Draft 3. Specifically, Draft 3 provided 24 calendar months for unplanned changes resulting in new BES Cyber Systems or a higher categorization for existing BES Cyber Systems, whereas the new Implementation Plan only provides 12 months. The wording of Question 2 does not make that clear. Request industry be advised of this impact.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment. The SDT issued the following statement in the request for comments: "Responses regarding the Planned and Unplanned changes section within CIP-002-6 were received from the June – July, 2019 comment and initial ballot period. Upon consideration of these comments and the issues raised, the drafting team determined that the matter of the CIP-002 identification and categorization periodicity is a larger issue that needs to be addressed holistically within CIP-002 including its requirements and criteria. Therefore, the team voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The CIP-002-6 standard will move forward with the Transmission Owner Control Center modifications and other minor	

updates (i.e., removal of the retired term SPS, etc.).” An entity that identifies its first high impact or medium impact BES Cyber System due to an unplanned change is given 24 months to comply with the applicable CIP standards.	
David Jendras - Ameren - Ameren Services – 3	
Answer	Yes
Document Name	
Comment	
Ameren supports EEI comments for this question; therefore we support the proposed modification.	
Likes 0	
Dislikes 0	
Response: Please reference the SDT’s response to EEI.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Reclamation supports the concept of different compliance implementation dates for planned versus unplanned changes. Reclamation recommends the compliance implementation date be calculated from the date the modified BES Cyber System is capable of impacting the BES. This will allow time for testing and returning existing equipment to service without the need to document compliance of equipment that is not capable of causing an adverse reliability impact.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment. This modification is outside the scope of our SAR. The team will consider this comment for the upcoming SAR to be submitted.	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Pam Feuerstein - Intermountain REA - 3	
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	
Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
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	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
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	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch	
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	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Womack - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Lee - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP – 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
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	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
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	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends including additional examples under Planned Changes to include Generation Facilities and Control Centers. Responsible Entities have struggled with the interpretation of what “*upon the commissioning*” means. Texas RE noticed the following: • “Responsible Entities” is capitalized throughout the Standard but not in the Implementation Plan. Texas RE recommends the term be capitalized and the language explaining “Responsible Entities” added for clarity and consistency. • In the table for “unplanned changes” the term “Medium-Impact” is capitalized/hyphenated and should not be for consistency.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment. The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The noted capitalization issues have been resolved.	

3. ***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.***

James Baldwin - Eugene Water and Electric Board - 1,3 - WECC	
Answer	No
Document Name	
Comment	
Instead of the SDT pulling more entities into the Medium Impact Category, EWEB suggests that the CIP Low requirements be enhanced to establish greater Critical Infrastructure Protection. The difference between the CIP Low and CIP Medium Requirements is drastic, closing this gap would enhance security without over-burdening smaller entities that pose little to no threat to the BES.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment. The Project 2016-02 SDT modified CIP-003-7 as detailed in the Standards Authorization Request. Any further modifications are outside the scope of this project. (Add language on what we did and establishing the floor. See above.)	
Daniel Gacek - Exelon – 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the proposed modification in terms of the flexibility it provides to meet reliability objectives in a cost effective manner..	
Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comment.	
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., 1, 3, 6, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	
Westar Energy and Kansas City Power & Light support Edison Electric Institute's response.	
Likes 0	
Dislikes 0	
Response: Please see the SDT's response to EEI's comment.	
Masuncha Bussey - Duke Energy - 1,3,5,6 – SERC	
Answer	Yes
Document Name	
Comment	
Duke Energy generally does not agree that the proposed modifications in CIP-002-6 are cost effective. Duke Energy generally does not agree that they pose a financial burden.	
Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comment. As the proposed modifications allow for some entities of low impact to the BES to have their BES Cyber Systems in the low impact category, it is more cost effective for those entities. It is realized that the change affects a small number of entities, and for others who are not affected by the 2.12 criteria it can just be a documentation change that would have some cost.

Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson	
Answer	Yes
Document Name	
Comment	
As provided in PG&E comments as part of the July 2019 comment and ballot period, PG&E believes the 24 month time-frame is sufficient to apply the necessary Requirement changes when the impact rating goes from low to medium, or medium to high. While PG&E has not experienced changes in impact rating that would elevate a BCS impact rating, our experience on the application of the Requirements for medium and high BCS does not suggest a longer time-frame would be necessary.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment.	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	

Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Volkmann - Glencoe Light and Power Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chinedu Ochonogor - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kjersti Drott - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
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	
Jeff Ipsaro - Silicon Valley Power - City of Santa Clara - 4	
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	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Val Ridad - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
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	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stacy Lee - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Womack - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
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	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nicholas Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
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	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Johnson - NRG - NRG Energy, Inc. - 5,6 - MRO,WECC,Texas RE,NPCC,SERC,RF	
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	
Pam Feuerstein - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren supports EEI comments for this question; therefore we will not submit comments on cost effectiveness of the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	

Answer	
Document Name	
Comment	
See EEI comments.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	
No NERC needs to include real cost estimate. Take a look at a recent WECC Controls webinar and include those cost too in all standards.	
Likes 0	
Dislikes 0	
Response: The SDT cannot provide cost estimates since the costs are dependent on any entity's particular systems and architecture. This question is designed for the entity to use their knowledge of their infrastructure and provide feedback to NERC and the SDT on the cost impact of a proposed change. For this particular modification to CIP-002, criteria 2.12, the SDT has modified the criteria such that it allows some entities that are low impact to potentially move some BES Cyber Systems from medium to low impact and could actually result in a cost reduction for those entities.	

4. *If you have additional comments on the proposed CIP-002-6 that you have not provided in response to the questions above, please provide them here*.

Marty Hostler - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	

New IRC 2.12 does not need to say **BES** Transmission lines or **Monitored and Controlled**. CIP-002-5.1a Page 2 Applicability Section 4.2.2 already says "All BES Facilities" it does not say non-BES facilities! Further, the GTB (CIP-002-5.1a GTB page 18) already mentions both Control and Monitor have to occur for a generator's or transmission line's capability to be included in an IRC 2.11 or 2.12 evaluation.

I believe this is all being done because FERC incorrectly produced section 3 page 10 of https://ferc.gov/legal/staff-reports/2017/10-06-17-CIP-audits-report.pdf. FERC's report says "For example, Criteria 2.11 requires categorization as Medium Impact of all Control Centers or backup Control Centers, not already categorized as High Impact, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. To determine whether a generation Control Center or back-up Control Center meets the 1500 MW threshold, the MW capacity of both BES generation and non-BES generation are considered. During audit fieldwork, staff found that some entities were only considering BES generation in applying Criteria 2.11, and therefore excluding all "non-BES generation" in their calculations. Foot note 9." Footnote 9 on Page 10 says "CIP-002-5.1a Attachment 1 does not define, or differentiate between, the terms "BES Generation," and "Non-BES Generation." Why would a GOP perform functional obligations of a GOP for a non-BES Generator? Non-registered entities that run generation don't need to! You don't have a CFR for a non-BES unit! There are no NERC obligations for a non-BES Unit!

In my view FERC's footnote 9 is misleading: CIP-002-5.1a GTB page 17 clearly says: While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this **applicability scoping section**. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and **represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply**. **The IRCs are all in Attachment 1**, thus only BES Generator and Lines are to be considered for IRC 2.11 and 2.12!). Consequently, there is no need to consider non-BES generation since Items in Attachment 1 pertain to BES Facilities only.

Additionally, FERC and NERC still have not answered my questions raised during drafting team phone/webinar meetings "What Generator or Transmission Operator Services does a GOP/TOP provide a non-BES generator/transmission line/substation?"

Why would a GOP/TOP provide said unnecessary services when entities that are not NERC registered who own and run generators and transmission lines don't need to provide GOP/TOP services to the very same/similar non-BES assets?

It is unfair to require GOP/TOPs to incur extra NERC Compliance costs for their Control Centers due to non-BES assets capability inclusion. NERC rules clear state "A reliability standard shall not give any market participant an unfair competitive advantage". Making GOPs/TOPs pay Control Center compliance costs for non-BES assets they operate is unfair as non-GOPs that own and run the same/similar units do not have to pay extra NERC cost for non-BES assets' they control and monitor from a central location(s).

It ironic that NERC recently had another Project recently up for Ballot "Moving Technical Rational Sections" out of standards. Why? NERC/FERC are already ignoring the GTB and the applicability sections too? Waste of money and more confusion; have to reference several documents to comply with a single standard.

Likes 0	
Dislikes 0	

Response: Thank you for your comment. The Project 2016-02 Modification to CIP Standards Drafting Team developed the revisions to criterion 2.12 based on feedback from industry stakeholders that participated in the NERC CIP V5 Transition Advisory Group. The group of stakeholders identified ambiguity as it relates to entities that perform the functional obligation of the Transmission Operator. Previously, BES Cyber Systems associated with TO and TOP Control Centers that were not high impact had to at least be categorized as medium impact. There was no threshold below which these systems could fall to be categorized as low impact. Criterion 2.12 was revised so TO/TOP Control Centers that did have BES Cyber Systems of truly lower risk could fall below the medium impact threshold and be considered low impact. The table included in the SDT's proposed revision excludes Transmission Lines operated below 100 kV in accordance with the Bulk Electric System definition. The SDT thanks you for your comment regarding criterion 2.11, however the project 2016-02 SDT is not authorized to revise Criterion 2.11.

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	
Comment	

NV Energy believes additional guidance is necessary regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity.

Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?

Likes 0	
Dislikes 0	

Response: The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The purchase of an asset would constitute a planned change and the BES Cyber System(s) would have to be compliant upon the purchasing entity's categorization of the BES Cyber System(s).

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

EEI offers for SDT consideration the following additional comments on Draft 4 of CIP-002-6:

1. Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - "transitioning from Version 4 to Version 5" and "(as that term is used in Version 4)".
2. Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model , therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC's

Organization Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting.

3. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC's Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016.
4. The footnote on all pages (i.e., page 10 moving forward) incorrectly still reference Draft 3 of CIP-002-6.
5. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1.
6. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded.

Likes 0	
Dislikes 0	

Response: Thank you for your comment. The team will note your edits and cleanup will take place during the virtualization modifications.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	
Document Name	

Comment

We request additional guidance regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity.

Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?

Likes 0	
Dislikes 0	
Response: The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The purchase of an asset would constitute a planned change and the BES Cyber System(s) would have to be compliant upon the purchasing entity's categorization of the BES Cyber System(s).	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
We thank the SDT for allowing us to provide comments on these changes.	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	
Document Name	
Comment	
San Miguel appreciates the efforts of the SDT on this project.	
Likes 0	
Dislikes 0	

Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI appreciates the efforts of the SDT on these issues.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the following: • In the section “BES Cyber Systems”, there appears to be incorrect grammar in first sentence discussing transition. • Starting on page 10, the footer information contains the incorrect draft version and date.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment. The version will be removed by the final ballot period and will no longer be shown.	

Bobbi Welch - Bobbi Welch On Behalf of: David Zwergel, Midcontinent ISO, Inc., 2; - Bobbi Welch	
Answer	
Document Name	
Comment	
MISO supports the additional clarity provided in the Supplemental Material (on page 29, under "Medium Impact Rating" and page 38 under "Low Impact Rating"); i.e. "No additional evaluation is necessary for BES Cyber Systems that have already been identified as high (or medium) impact."	
Likes 0	
Dislikes 0	
Response: Thank you.	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Comments: EEI offers for SDT consideration the following additional comments on Draft 4 of CIP-002-6: 1. Page 5 of the Redline, Section 6, Background, under subheading “BES Cyber Systems”, the first word in the sentence (transitioning) needs to be capitalized. 2. Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - “transitioning from Version 4 to Version 5” and “(as that term is used in Version 4)”. 3. Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model , therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC’s Organization	

Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting.

4. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC's Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016.

5. The footnote on all pages (i.e., page 10 moving forward) incorrectly still references Draft 3 of CIP-002-6.

6. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1.

7. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded.

Likes 0	
Dislikes 0	

Response Team will address during virtualization modification stage.

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 3, 4, 5; John Cook, North Carolina Electric Membership Corporation, 3, 4, 5; Luis Fondacci, North Carolina Electric Membership Corporation, 3, 4, 5; - Kagen DelRio

Answer	
Document Name	

Comment

NCEMC appreciates the efforts of the SDT on these issues.

Likes 0	
Dislikes 0	

Response	
Michael Johnson - Michael Johnson On Behalf of: Marco Rios, Pacific Gas and Electric Company, 1, 3, 5; - Michael Johnson	
Answer	
Document Name	
Comment	
PG&E provides no additional comments.	
Likes 0	
Dislikes 0	
Response	
Masuncha Bussey - Duke Energy - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Duke Energy has the following additional comments - The second paragraph in Criterion 2.1 on page 29 of 45 states "to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024" The MOD-024 Standard has been retired and should be removed as a reference.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment. This cleanup will be completed during the virtualization modifications.	
Barry Lawson - National Rural Electric Cooperative Association – 4	

Answer	
Document Name	
Comment	
NRECA appreciates the efforts of the SDT on these issues.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
While draft 3 provided additional time (24 calendar months) for unplanned changes resulting in new BES Cyber Systems or a higher categorization for existing BES Cyber Systems, Southern understands that removing the proposed change associated with "time frames to implement" while reverting to the previous language makes sense. We look forward to the opportunity to actively participate in addressing this as a part of a future proposed change which encompasses addressing planned and unplanned changes, as a whole.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	

Comment	
Provide clearer examples for each of the listed items in the implementation table for the unplanned section.	
Likes 0	
Dislikes 0	
Response: Thank you for your comment. The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon supports the comments offered by EEI, as reflected here:	

1. Page 5 of the Redline, EEI suggests that all references to Version 4 and 5 should be removed from the Standard. We are now on Version 6 and the following language should be removed from the standard - “transitioning from Version 4 to Version 5” and “(as that term is used in Version 4)”. 2. Page 6 and page 28 of the Redline: EEI suggests removing all references to the NERC Functional Model. (See Reliable Operation of the BES/P6 and High Impact Rating/P28). NERC has decided to no longer maintain the Functional Model , therefore it should not be referenced in Reliability Standards. Instead, the SDT should make references to the appropriate sections of NERC’s Organization Registration and Certification Manual and the Compliance Registry Criteria, per the determination made by the Standards Committee at their October 2019 meeting. 3. Page 7 of the Redline: Remove the bulleted examples for EACMS, PACS and PCA given all three are defined terms in NERC’s Glossary of Terms and the definition for EACMS and PACs were both adopted by the NERC BOT on 12/26/2012 and approved by FERC on 11/22/2013, while PCA was adopted by the NERC BOT on 2/12/2015 and approved by FERC on 1/21/2016. 4. The footnote on all pages (i.e., page 10 moving forward) incorrectly still reference Draft 3 of CIP-002-6. 5. Page 17 of the Redline: Remove the second listing of the title (Impact Rating Criteria) at the top of Attachment 1. 6. Page 22 of the Redline: EEI supports the SDT decision to not remove the Guidelines and Technical Basis at this time, in order to ensure changes made to CIP-002-6 are not needlessly delayed. However, we do ask that the GTB be removed within Project 2016-02 before the current SDT is disbanded	
Likes 0	
Dislikes 0	
Response: Please see the SDT’s response to EEI’s comment.	
Kent Feliks - AEP – 3	
Answer	
Document Name	
Comment	

AEP has no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
We request additional guidance regarding Planned and Unplanned Changes with respect to acquisition of new BES assets from another Entity. Would any BES Cyber Systems compliance issues discovered after acquisition of the Assets already commissioned by the selling Entity be subject to immediate compliance with CIP Cyber Security Standards, or would this discovery by the purchasing Entity constitute an Unplanned Change with 12 months to achieve compliance?	
Likes 0	
Dislikes 0	
Response: The SDT voted to restore the Planned and Unplanned Changes section to its previous state within the Implementation Plan and a Standard Authorization Request will be drafted to address these types of modifications in a future project. The purchase of an asset would constitute a planned change and the BES Cyber System(s) would have to be compliant upon the purchasing entity's categorization of the BES Cyber System(s).	
Anthony Jablonski - ReliabilityFirst – 10	
Answer	

Document Name	
Comment	
The posted version has incorrect grammar in R1, Parts 1.1 and 1.2. Please change Part 1.1 from "Identify each of the high impact BES Cyber System" to "Identify each high impact BES Cyber System". Please change Part 1.2 from "Identify each of the medium impact BES Cyber System" to "Identify each medium impact BES Cyber System". Also please consider requiring explicit identification of associated systems (currently EACMS, PACS, PCA) for inclusion in the standard language (e.g. R1 P1.4) for high and medium impact BES Cyber Systems. Suggested wording: "Identify each EACMS, PACS, and PCA associated with a high impact BES Cyber System or a medium impact BES Cyber System." This addition would serve to remind Responsible Entities that such identifications are required, and will permit assessing a violation, if applicable, against only one Requirement.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment. Will be cleaned up during virtualization modifications. **Outside the scope of this SAR and will be considered for a future project.**	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI comments for this question.	
Likes 0	
Dislikes 0	
Response: Please see the SDT's response to EEI.	
Richard Jackson - U.S. Bureau of Reclamation – 1	
Answer	
Document Name	
Comment	
Reclamation recommends the SDT add the definitions of Planned Changes and Unplanned Changes to the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response: The SDT thanks you for your comment. The SDT will draft a SAR to address Planned/Unplanned Changes in a future project.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC – 1	
Answer	
Document Name	
Comment	
ATC supports the commetns of EEI.	
Likes 0	
Dislikes 0	
Response: Please see the SDT's response to EEI's comment.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	
Document Name	
Comment	
I find the standard difficult to read with the various references back and forth between the Standard and Attachment 1. Ideally, the references should be mimized. This may be an issue in enforcement, and could cause some confusion to some entities.	
Likes 0	
Dislikes 0	

Response: The SDT thanks you for your comment. The requested changes are beyond the scope of the project.

End of report.