NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

## Consideration of Comments on Project 2008-06

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

## Index to Questions, Comments, and Responses

The Industry Segments are:

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7 — Large Electricity End Users
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9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Group | Janet Smith | Arizona Public Service Company | X | | X | | X | | | | | |
| 2. | Group | Denise Koehn | Bonneville Power Administration | X | | X | | X | X | | | | |
| 3. | Group | Mike Garton | Electric Market Policy | X | | X | | X | X | | | | |
| 4. | Group | Michael Gammon | Kansas City Power & Light | X | | X | | X | X | | | | |
| 5. | Group | Carol Gerou | MRO's NERC Standards Review Subcommittee | | | | | | | | | | X |
| 6. | Group | Guy Zito | Northeast Power Coordinating Council | | | | | | | | | | X |
| 7. | Group | Larry Saxon | OGE | X | | X | | X | | | | | |
| 8. | Group | David K Thorne | Pepco Holdings Inc and Affiliates | X | | X | | | | | | | |
| 9. | Group | JT Wood | Southern Company Transmission | X | | X | | | | | | | |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 10. | Group | Paul McClay | Tampa Electric | X | | X | X | X | | | | | |
| 11. | Individual | Kenneth A. Goldsmith | Alliant Energy | | | | X | | | | | | |
| 12. | Individual | Kirit Shah | Ameren | X | | X | | X | X | | | | |
| 13. | Individual | Andrew Pusztai | American Transmission Company | X | | | | | | | | | |
| 14. | Individual | Dan Klempel | Basin Electric Power Cooperative | X | | X | | X | | | | | |
| 15. | Individual | Bill Keagle | BGE | X | | | | | | | | | |
| 16. | Individual | Tony Kroskey | Brazos Electric Power Cooperative, Inc. | X | | X | | X | | | | | |
| 17. | Individual | Steve Alexanderson | Central Lincoln | | | X | X | | | | | | |
| 18. | Individual | Jeffrey Mead | City of Grand Island | | | | | X | | | | | |
| 19. | Individual | John Allen | City Utilities of Springfield, Missouri | X | | | X | | | | | | |
| 20. | Individual | Brenda Powell | Constellation Energy Commodities Group | | | | | | X | | | | |
| 21. | Individual | Greg Rowland | Duke Energy | X | | X | | X | X | | | | |
| 22. | Individual | Dan Roethemeyer | Dynegy Inc. | | | | | X | | | | | |
| 23. | Individual | Doug Hohlbaugh | FirstEnergy | X | | X | X | X | X | | | | |
| 24. | Individual | Marc A. Child | Great River Energy | X | | X | | X | X | | | | |
| 25. | Individual | Joe Knight | Great River Energy | X | | X | | X | X | | | | |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 26. | Individual | John Kutzer | Independent Consultant | | | | | | | | X | | |
| 27. | Individual | Dan Rochester | Independent Electricity System Operator | | X | | | | | | | | |
| 28. | Individual | Rick Terrill | Luminant | | | | | X | X | | | | |
| 29. | Individual | Joe Petaski | Manitoba Hydro | X | | X | | X | X | | | | |
| 30. | Individual | Jason L. Marshall | Midwest ISO | | X | | | | | | | | |
| 31. | Individual | Randi Woodward | Minnesota Power | X | | | | | | | | | |
| 32. | Individual | Joe O'Brien for Tim Conway | NIPSCO | X | | X | | X | X | | | | |
| 33. | Individual | Michael Lombardi | Northeast Utilities | X | | X | | X | | | | | |
| 34. | Individual | Kelsi Oswald | Pinellas County Resource Recovery Facility | | | | | X | | | | | |
| 35. | Individual | Adam Menendez | Portland General Electric Company | X | | X | | X | X | | | | |
| 36. | Individual | Barry J Skoras | PPL Electric Utilities Corporation | X | | | | | | | | | |
| 37. | Individual | Matt Brewer | San Diego Gas and Electric | X | | X | | X | | | | | |
| 38. | Individual | Jim Stanton | SPS Energy | | | | | | | | X | | |
| 39. | Individual | Scott Amsden | Tacoma Power | X | | X | X | X | X | | | | |
| 40. | Individual | andres lopez esquerra | USACE | | | | | X | | | | | |

| Group/Individual | | Commenter | Organization | Registered Ballot Body Segment | | | | | | | | | |
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| 41. | Individual | Louise McCarren | WECC | | | | | | | | | | X |
| 42. | Individual | Candace Morakinyo | Wisconsin Electric Power Company d/b/a We Energies | | | | | X | X | | | | |

## 1. When reviewing the changes to the proposed CIP-002-4 standard, do you believe that the proposed standard was responsive to feedback received and provides acceptable bright-line criteria for the determination of Critical Cyber Assets?

**Summary Consideration:** In general, most commenters stated that they believed the proposed standard was responsive to feedback received and provides acceptable bright-line criteria for the determination of Critical Cyber Assets. The following summary of comments and responses is grouped by areas of CIP-002-4.

General Comments:

Concern was expressed that any clarification included in the Guidance Document should be made part of the Standard. The SDT responded that, while the Guidance Documents are not the standard, they do provide additional context. Other entities expressed concern that the bright line prescribed in Attachment 1 will still include smaller Registered Entities that do not have significant impact on the reliable operation of the BES. The SDT responded that in FERC Order 706, the Commission addressed the importance of Critical Assets, no matter how small. Another entity stated that there needs to be a clear and consistent method for Planning to identify IROLs, or it becomes subjective and open to interpretation. The SDT responded that the purpose of FAC-014-2 Requirements R3 and R4 is to establish a clear and consistent method for identifying IROLs. The method for Planning to identify IROLs is beyond the scope of the CIP standards. Several entities expressed an interest that the SDT should take steps to reduce ambiguous language. (e.g. black start resources). The SDT responded that they have made efforts to reduce any ambiguous language, to the point of using the NERC glossary term “Blackstart Resources” in order to eliminate any confusion over the term.

Several entities stated that the SDT should clarify that substations are the facilities to be identified as Transmission Critical Assets, not lines, transformers, reactive equipment, etc. The SDT responded that substations are not the only Facilities identified as Critical Assets. Lines, transformers, reactive equipment, and other Facilities can be classified as a Critical Asset if they meet any of the criteria in Attachment 1. The SDT referred commenters to the posted guidance document for additional clarification. One entity expressed concern that many items give one entity the power to designate facilities owned by another entity as critical. The SDT responded that the issue of communication between entities is recognized as an issue that needs to be addressed and will be considered in a future version. Some entities felt that the SDT was prescriptive in determining Critical Assets, which they felt was contrary to FERC Order 706. The SDT responded that the Attachment 1 criteria were developed in response to an external oversight directive in the FERC Order 706. In consideration of this directive, the SDT decided there did not exist across all regions an appropriate third party to provide this type of oversight. Also, external review and oversight carries with it the compliance overhead and arbitration processes analogous to the TFE process. This “bright-line” criteria approach removes the variability of entity defined methodologies that would prompt the need for external review. Additionally, some entities expressed concern that the SDT should begin a similar effort in identifying a bright line criteria for Critical Cyber Assets. The SDT responded that the scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method, not the Critical Cyber Asset Identification method.

Nuclear Applicability:

Several entities expressed concern about the nuclear generation exemption language for nuclear generation plants located in the United States (U.S.) along with the parenthetical text of Attachment 1 criterion stating "including nuclear generation." They expressed that this leaves the standard ambiguous and in need of clarification based on recent Nuclear Regulatory Commission (NRC) findings. The NRC and NERC have worked closely to address FERC's Order 706B concerns related to any nuclear balance of plant (BOP) systems, structures and components (SSCs) within a U.S. nuclear power plant that is not regulated by the NRC and subject to NERC CIP standards. However, the NRC letter to NERC dated November 26, 2010 clarifies its findings that "Based on the Commission's [NRC] determination, the NRC staff does not believe that there will be any SSCs in the BOP that will fall under NERC's Critical Infrastructure Protection (CIP) standards." The SDT responded that the phrase "including nuclear generation" in criterion 1.1 is there to define a plant site. Unit output from all units at a single plant site should be included to determine if a plant meets the 1500MW threshold. The evaluation for Critical Cyber Assets is similar. Although it is highly unlikely that nuclear and non-nuclear units share common Cyber Assets, the evaluation should still occur. In addition, the Applicability language has been modified in light of the NRC letter.

Requirement R2:

An entity expressed concern that the requirement as written continues and does not solve the ambiguity with the current Critical Cyber Asset identification requirement. Specifically: "essential to the operation of the Critical Asset" needs to be defined; "adversely impact the reliable operation" needs to be defined; and, it is not clear what "within 15 minutes" means in this context. The SDT responded that the scope of changes to this Standard only addresses the near-term issues associated with external oversight and review of the risk-based assessment methodology. The subjectivity involved in the Critical Cyber Asset identification requirement will be addressed in future releases of these Standards. The 15 minute threshold is intended to include only those assets at generating units affecting real-time operations. This qualifier is particularly important to a generating plant because several systems (i.e. a fuel-handling system) may be essential after a longer period of time but do not necessarily involve real-time reliability impact.

Requirement R3:

An entity expressed concern that the SDT should confirm that under the proposed language for Requirement R3 the approval of the senior manager of the CCA list is only required on an annual basis, and that intermediate updates made "as necessary" under this Requirement do not require senior manager approval. Additionally, the SDT should confirm that under the proposed language for Requirement R3 that the timing of updates "as necessary" to the CCA list is left to the discretion of the entity, and that there is no expectation that such updates are completed within a certain period of time. The SDT responded that the intent of Requirement R3 is that the approval of lists by the senior manager is only required on an annual basis. The intermediate updates do not require senior management approval. The timing of the updates for the Critical Asset list and the Critical Cyber Asset list is not specified and is left to the discretion of the Responsible Entity.

Attachment 1:

Criterion 1.1

One entity expressed concern that criterion 1.1 needs to have "in a single interconnection" added to the end. They provided an example of a single plant site that resided in two Interconnections. The SDT incorporated the suggested wording as clarification of criterion 1.1. Another commenter was concerned about communication that is necessary between various Responsible Entities to identify Critical Assets. The SDT agreed that communication between various Responsible Entities will be required to ensure that all critical Assets are identified. Another commenter stated that the threshold for criteria 1.1, needs to be supported by engineering principles and transmission operations knowledge. The SDT responded that it performed an informal survey of the regions and identified what the megawatt value of the reserve sharing would be for various groups. The SDT used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Balancing Authorities in all regions.

Criterion 1.2

One commenter expressed that 1000 MVAR was too large, and that there are not any reactive resources that large in their region. They asked if the drafting team is aware of where any 1000 MVAR resources are located. The SDT responded that the survey that NERC conducted earlier this year showed that there were facilities that would qualify at this threshold.

Criterion 1.3

One commenter expressed that criterion 1.3 was not consistent with the goal of providing bright line requirements. This criterion requires entity to conduct a study and submit to the Reliability Coordinator, Planning Coordinator or Transmission Planner, who will then determine if a facility qualifies as critical. The SDT responded that there is no burden or obligation placed on the Planning Coordinator or Transmission Planner to designate any unit as needed to avoid Adverse Reliability Impacts in the long-term planning horizon. However, if the PC or TP has identified Adverse Reliability Impacts (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), then any units identified that avoid this scenario must be classified as a Critical Asset. Another entity stated that the term "long-term planning horizon" is referenced but is not clear within the Standard what it means or that it is defined elsewhere. The SDT responded that the resource document “Time Horizons” (found at http://www.nerc.com/files/Time_Horizons.pdf) was used to determine the long-term planning horizon. In this document, long-term planning is defined as “a planning horizon of one year or longer”

One commenter stated that the Reliability Coordinator should be the entity to determine the criticality of a generation Facility, based on information it receives from the Planning Coordinator. The SDT responded that based on the functional model the Planning Coordinator or the Transmission Planner are the correct entities to perform the evaluation. If it is determined through system studies that a unit must run in order to preserve the reliability of the BES, such as due to a category C3 contingency as defined in TPL-003 or a category D contingency as defined in TPL-004, then that unit must be classified as a Critical Asset.

Criterion 1.4

One commenter expressed concern that the Blackstart Resources term used in Criteria 1.4 and 1.5 is in the NERC Glossary and is used in EOP-005-2. However this standard and the related definition are not approved by FERC yet. So what happens if the definition of Blackstart Resource is significantly changed after approval of this standard? The SDT responded that this concern was noted prior to the second posting and the implementation plan was revised to clarify the issue.

Another commenter suggested that NERC consider a "Black Start Tier Methodology" in which only "Primary Black Start Units" would fall under stringent compliance scrutiny and obligations, while other "Secondary Tier Units" would still be made available with required annual testing and operating specifications but be taken off the scope of NERC compliance. The SDT responded that a tiered approach to Blackstart Resources is a good idea, and the SDT suggested that a SAR be submitted by the entity outlining this approach to EOP-005-2.

The APPA CIP Task Force identified what they believed to be an unintended consequence - a Catch-22 - from the interaction of the revised CIP-002-4 Attachment 1's Criteria 1.4 (Blackstart Resources) and 1.5 (identified Cranking Paths) with the control center size and facility exceptions in 1.15, 1.16 and 1.17. The SDT carefully selected criteria around the NERC Glossary term Blackstart Resource and its derivation from EOP-005-2. It was felt that these resources are critically important in their function to restore the BES under blackstart conditions. As such, these assets deserve protection as a Critical Asset. Due to their connectivity and configuration, control centers that operate these Blackstart Resources also have the ability to jeopardize their availability and function in a time of need if maliciously misused. As such, these control centers should also be deemed Critical Assets. The SDT appreciates the "catch-22" concern that was brought forth by APPA. However, the SDT does not believe that the criteria as written present a catch-22 scenario. A careful reading of EOP-005-2 indicates that those assets identified as Blackstart Resources are those needed to bring the shutdown area "to a state whereby the choice of Load to be restored is not driven by the need to control frequency or voltage." The APPA comments indicate that the assets of concern to them are being utilized "once voltage and frequency are stabilized." As such, these assets are not required to be included in the TOP's restoration plan as Blackstart Resources. Additionally, it should be noted that EOP-005-2 does not presume that Blackstart Resources are only those "located within the Transmission Operator's System." As such, smaller TOPs have the opportunity to coordinate with neighboring TOPs and the RC in the development of their restoration plan which may not necessarily identify Blackstart Resources in their own system. In light of these clarifications, the SDT does not believe that a catch-22 exists that would unnecessarily bring in all TOP/BA control centers regardless of size, but rather only those that have the potential to impact Blackstart Resources that are essential to BES restoration as identified through EOP-005-2.

Criterion 1.5

A few commenters suggested alternate wording for this criterion. The SDT discussed the merits of each, but ultimately decided to keep the posted wording unchanged.

Criteria 1.6 and 1.7

One commenter stated that this criterion should have another factor based on the size of the facility such that loss of the Facility would have an adverse impact on the BES. The SDT will take this suggestion under consideration for future revisions.

Another commenter believed the list of relevant transmission facilities developed by the Responsible Entity should be subject to an impact-based assessment by the Reliability Coordinator who has the wide-area view of the system. If necessary, an additional requirement that requires the RC to have a risk-based assessment methodology and to conduct the assessment should be included. Such an arrangement would be akin to the exemption provisions advocated by FERC in its Final Rule on Revisions to the ERO definition of Bulk Electric System. The SDT considered placing various analysis requirements on the Reliability Coordinator. The Functional Model describes the Reliability Coordinator as “The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” However, the nature of the Critical Asset list is long-term, since implementation of CIP-003 to CIP-009 is up to two years. Based on this, it was determined that the Reliability Coordinator was not an appropriate entity for this analysis.

Criterion 1.8 and 1.9

Several entities asked where the phrase “critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies” came from. The SDT responded that this phrase came from FAC-014-2 Requirement R5. One commenter stated that there should be some obligation that the parties that identify the Transmission Facility as critical also notify the Transmission Owner and Operator of that identification so the Transmission Owner and Operator are aware and can protect. The SDT responded that FAC-014-2 R5 contains information concerning communication of Facilities that are critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

Another commenter expressed that the Reliability Coordinator be removed from the criterion that identifies Critical Asset facilities based on Interconnection Reliability Operating Limits (IROLs). The SDT responded that according to FAC-014-2 Requirement R1 “The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.” Since they have a responsibility to ensure that the IROLs are established and consistent with their SOL methodology, it is valid to list them in this Criterion.

Another commenter stated that only the Reliability Coordinator develops IROLs, and as such should be the only entity to determine criticality, that the NERC Functional Model Version 5 identifies a Planning Coordinator, not a Planning Authority, and that since the Planning Coordinator is referred to in the standard, it must be included in the Applicability section. The SDT responded that FAC-014-2 Requirement R3 states “The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.” FAC-014-2 Requirement R4 states “The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority’s SOL Methodology.” FAC-014-2 Requirement R1 states “The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.” According to FAC-014-2, the Reliability Coordinator does not develop IROLs. They ensure that the IROLs are established, and that they are consistent with their SOL methodology. Planning Authority is referenced because of FAC-014-2 Requirement R3. Also, since the Planning Coordinator would not own any Critical Assets, they are not subject to CIP-002-4 and would not be listed as a Responsible Entity.

Criterion 1.10

Several commenters stated that the phrase "directly" should be included in Criterion 1.10 which existed in the previous draft. The SDT responded that several commenters in the first posting were concerned about the use of the term "directly." After consideration by the SDT, it was determined that the term could be removed without affecting the intent of the criterion. One commenter expressed concern that, in so much as Criterion 1.1 could result in the identification of generation plant locations with no Critical Cyber Assets, the resulting requirements in Criterion 1.10 could result in expending efforts protecting transmission assets that might not otherwise need to be protected, diverting resources that might be more effectively expended elsewhere. The SDT responded that the intent of Criterion 1.10 is to ensure the availability of Facilities necessary to support those generation Critical Assets. Any Transmission Facility that the loss of which would result in the loss of a Critical Asset identified in criterion 1.1 or 1.3 would need to be classified as a Critical Asset.

Criterion 1.11

Several commenters stated that this criterion should either be removed or revised to "Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements." The SDT responded that Criterion 1.11 is based on NUC-001-2 R9.2.2 "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." While the purpose of NUC-001-2 states "This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown," it is a NERC reliability standard and as such helps to ensure the reliability of the Bulk Electric System.

Criterion 1.13

Several commenters asked that the Guidance Document be modified to provide the reasoning behind the 300 MW criteria listed in criterion 1.13. The SDT responded that the posted Guidance document has been modified to add reasoning for the threshold level. Other commenters suggested alternate wording for the criterion. The SDT discussed the merits of each, but ultimately decided to keep the posted wording unchanged.

Some commenters stated that criterion 1.13 should be reworded to indicate that distributed UFLS or UVLS schemes (i.e., individual UF or UV relays operating independently in multiple substations) are not considered to be a critical asset. Collectively the UFLS or UVLS scheme may shed more than 300MW; however, due to the distributed nature of the scheme, the UFLS or UVLS schemes are not considered to be a critical asset. The SDT spent considerable time discussing the wording of criterion 1.13, and chose the term "Each" to represent that the criterion applied to a discrete system or Facility. The SDT responded that a discrete component that sheds more than 300MW of load due to the implementation of Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program is a Critical Asset. This criterion is intended to include as Critical Assets regional Under Frequency Load Shedding and Under Voltage Load Shedding schemes.

Criterion 1.15

One commenter asked for clarification on what the term "control" means. The SDT responded that from the posted Guidance document: “A control center or generation control center that provides critical operating functions and tasks as identified in CIP–002 must be protected per the requirements of the Cyber Security Standard. The monitoring and operating control function includes controls performed automatically, remotely, manually, or by voice instruction.” Another entity expressed concern that if a small utility, as a joint owner, has control over only a small portion of a large plant that falls under the brightline of criterion 1.1, they are concerned that as currently written, the first sentence of criterion 1.15 would designate this small utility’s control center as critical. The SDT responded that the concern is that the joint owner’s control center could provide a path to compromise the functionality of the generation designated a Critical Asset.

Criteria 1.16 and 1.17

One commenter stated that they believe that in Criterion 1.16 the functional obligation should be clearly defined to include those pertaining to the real-time operations and NOT all. The SDT responded that due to the direct impact on the operation of identified Critical Assets, these Transmission control centers must be designated as Critical Assets. Attachment 1 criteria are used to identify control centers as Critical Assets. The consideration of specific reliability functions would be a part of the entity identifying Critical Cyber Assets which support the control center.

Implementation Plan

One entity stated that the proposed implementation is too aggressive. Physical Security Perimeters are expensive and it may not be possible to fund these modifications in the short timeframe for compliance. A 3-year implementation period would be more appropriate. The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC Approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset.

| Organization | Yes or No | Question 1 Comment |
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| Arizona Public Service Company | Yes | |
| Dynegy Inc. | Yes | |
| NIPSCO | Yes | |

| Organization | Yes or No | Question 1 Comment |
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| Northeast Utilities | Yes | |
| Portland General Electric Company | Yes | (1) The Standard Drafting Team (SDT) should confirm that under the proposed language for Requirement 1 the approval of the senior manager of the CCA list is only required on an annual basis, and that intermediate updates made "as necessary" under this Requirement do not require senior manager approval.(2) The SDT should confirm that under the proposed language for Requirement 1 that the timing of updates "as necessary" to the CCA list is left to the discretion of the entity, and that there is no expectation that such updates are completed within a certain period of time. |
| **Response:** Thank you for your comments.<br><br>The intent of Requirement R3 is that the approval of lists by the senior manager is only required on an annual basis. The intermediate updates do not require senior management approval. The timing of the updates for the Critical Asset list and the Critical Cyber Asset list is not specified and is left to the discretion of the Responsible Entity. | | |
| Ameren | No | . We suggest Criteria 1.6, 1.7 and 1.10 should be changed to include substations and switchyard (station) only and not “Facilities”. Based on the definition of “Facilities” and application of Criteria 1.6, 1.7 and 1.10, the Critical Asset list now would include transmission lines. Our concern is that there will be significant issue to comply with CIP-003 through CIP-009 (for example, physical security requirements) for the transmission line assets, if some components installed on the lines fall into cyber asset category, such as temperature or flow monitoring devices or fiber optics used for communication.<br>2. The Blackstart Resources term used in Criteria 1.4 and 1.5 is in the NERC Glossary and is used in EOP-005-2. However this standard and the related definition are not approved by FERC yet. So what happens if the definition of Blackstart Resource is significantly changed after approval of this standard? We suggest that the definition of Blackstart Resources should be included in this standard.<br>3. The phrase “directly” should be included in Criterion 1.10 which existed in the previous draft. We believe that after removing this term, the revised wordings now are more confusing.<br><br>4. We believe that in Criterion 1.16 the functional obligation should be clearly defined to include those pertaining to the real-time operations and NOT all. We suggest that Criterion 1.16 should be modified to read “Each control center or backup control center used to perform the functional |

| Organization | Yes or No | Question 1 Comment |
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| | | obligations, pertaining to real time operation of the BES, of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12.”<br><br>5. We believe that in Criterion 1.17 the functional obligation should be clearly defined to include those pertaining to the real-time operations and NOT all. Further this criterion should make clear that the 1500 MW is calculated on the same basis as defined in Critetion 1.1. We suggest that Criterion 1.17 should be modified to read, “Each control center or backup control center used to perform the functional obligations, pertaining to real time operation of the BES, of a Balancing Authority if its Balancing Authority Area(s) includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. Each control center or backup control center used to perform the functional obligations pertaining to real time operation of the BES, of a Balancing Authority if its Balancing Authority Area(s) includes an aggregate of 1500 MW in a single Interconnection, calculated using the highest rated net Real Power capability of each unit during the preceding 12 months.<br><br>6. During the Webinar, references were made to the Guidance Document. However, the Guidance Document is NOT the standard and can not be used in the compliance audit. So, any clarification included in the Guidance Document should be made part of the Standard. |

**Response:** Thank you for your comments.

1. The SDT does not feel this change is necessary. Please refer to the first bullet in the Overall Application of Attachment 1 in the posted Guidance document for a discussion of the SDT’s reason for the use of the term “Facility.”
2. Your concern was noted prior to the second posting and the implementation plan was revised with the following: “The term Blackstart Resource, used in CIP-002-4 Attachment 1, was submitted for regulatory approval with Project 2006-03 – System Restoration and Blackstart. The definition must be approved before Criteria 1.4 and 1.5 are used to determine Critical Assets for Responsible Entities.” The language has been revised in this posting to “The term Blackstart Resource, used in CIP-002-4 Attachment 1, was submitted to FERC for regulatory approval in the US with Project 2006-03 – System Restoration and Blackstart. The Effective Date of EOP-005-2 is the date that Criteria 1.4 and 1.5 will be used to determine Critical Assets for any Responsible Entity.”
3. Several commenters in the first posting were concerned about the use of the term “directly.” After consideration by the Standard Drafting Team, it was determined that the term could be removed without affecting the intent of the criterion.
4. Due to the direct impact on the operation of identified Critical Assets, these Transmission control centers must be designated as Critical

| Organization | Yes or No | Question 1 Comment |
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| Assets. Attachment 1 criteria are used to identify control centers as Critical Assets. The consideration of specific reliability functions would be a part of the entity identifying Critical Cyber Assets which support the control center.<br>5. Due to the direct impact on the operation of identified Critical Assets, these Balancing Authority control centers must be designated as Critical Assets. The impact to the identified Critical Assets would be in real time, as the Balancing Authority functions in the Functional Model involve real time operations. If a Balancing Authority can control 1500MW or more of generation, it is considered a Critical Asset. The language in criterion 1.1 was taken from MOD-024, which is only applicable to Generation Owners.<br>6. While the Guidance Documents are not the standard, they do provide additional context. The SDT believes the wording in the posted standard provide sufficient clarity. | | |
| Kansas City Power & Light | No | o The bright line prescribed here will still include smaller Registered Entities that do not have significant impact on the reliable operation of the BES. The bright line components that need to be considered for modification are those regarding control centers and the blackstart facility considerations. It may be easiest to consider the role system load could play in the entirety of this bright line. For example, leave the bright line language as is, but those entities with 500 MW of system load or less are exempt.<br><br>o Section 1.8 is not clear as to the intent. If the intent is to include those facilities that are identified as IROL flowgates then it is recommended the Drafting Team consider the following language, “Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as a LODF flowgate with an IROL limit established and the associated contingent facility(ies).” If this is not the case what does, “critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies” mean?<br><br>o Section 1.9 is not clear as to the intent for the same reasons stated for section 1.8. If the intent is to include those facilities that are identified as IROL flowgates then it is recommended the Drafting Team consider the following language, “Flexible AC Transmission Systems (FACTS), at a single station or substation location, that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as a LODF flowgate with an IROL limit established and their associated contingent facility(ies). If this is not the case what does, “critical to the derivation of Interconnection |

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| | | Reliability Operating Limits (IROLs) and their associated contingencies” mean? |
| **Response**: Thank you for your comments.<br>• In FERC Order 706, the Commission addressed the importance of Critical Assets, no matter how small. An entity with 500MW or less of system load may still have a Critical Asset which needs to be evaluated for possible Critical Cyber Assets.<br>• The wording for criterion 1.8 came from FAC-014-2 Requirement R5.<br>• The wording for criterion 1.9 came from FAC-014-2 Requirement R5. | | |
| Great River Energy | Yes | After reviewing the SDT summary of comments and their associated edits to Attachment 1, GRE feels the changes were responsive to the feedback received by industry in the previous comment/ballot period. |

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| **Response**: Thank you for your comment. | | |
| Alliant Energy | No | Alliant Energy agrees with most of the changes to the standard, however, Attachment 1, Criterion 1.4 concerning Blackstart Resources is unacceptable as currently written. Alliant Energy fears that there will be a degradation of the Black Start program as it exists today. The industry has already seen companies removing their black start resources from Power System Restoration Plans due to compliance requirements which entail additional costs associated with not only bringing these units up to the required standards but the extensive fines which may occur if rigid compliance specifications are not met. We would respectfully suggest that NERC consider a “Black Start Tier Methodology” in which only “Primary Black Start Units” would fall under stringent compliance scrutiny and obligations, while other “Secondary Tier Units” would still be made available with required annual testing and operating specifications but be taken off the scope of NERC compliance. This methodology would promote back up facilities to the primary black start units and would encourage smaller black start units to remain in the black start program which could be used to expedite the restoration process. A “Black Start Area Plan” could be created to specify the “Primary Black Start Units” and “Secondary Black Start Units” requirements for a given footprint or specified loading area. A minimum of one “Primary Black Start Unit” would be required for any specific footprint with special additional considerations for those units which may supply stabilization power to nuclear facilities. The Black Start Tariff could be utilized to maintain the “Primary Black Start Units” availability and be used to reward the availability of the “Secondary Black Start Units”. The tariff could also be used by those entities which do not physically have such facilities but could contract to support this kind of services. A third possible tier of black start units could be defined and incorporated which would be comprised of larger coal/gas units with only black start stabilization capability. Incorporating these third tier units would enable coal/ gas units to self supply their own stabilization power and would be immediately made available to contribute to the loading and stabilization of the black start area plan once the skeletal grid was reconstructed. These types of units could also be rewarded through the black start tariff to ensure unit availability, and promote the reduction of unit damage which can occur to generating stations during a black out situation. |

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| **Response**: Thank you for your comments. A tiered approach to Blackstart Resources is a good idea, and the drafting team suggests that a SAR be submitted by the entity outlining this approach to EOP-005-2. It is beyond the scope of this SDT. | | |
| American Transmission Company | No | ATC believes that Attachment 1, the so-called bright line criteria, language needs to be clarified.<br><br>There needs to be a clear and consistent method for Planning to identify IROLs, or it becomes subjective and open to interpretation. The following are ATC's recommended changes to the Criteria listed:<br><br>Criterion 1.3: o Not consistent with the goal of providing bright line requirements. This criterion requires entity to conduct a study and submit to the RC, PC or TP, who will then determine if a facility qualifies as critical. These criteria will likely result in inconsistent and unrepeatable studies being performed by RC, PC or TP. Comment also applies to 1.8, 1.9. o Suggestion: Delete this criterion at the next CIP-002 revision.<br><br>Criterion 1.8: o The ‘critical to the derivation of . . . and their associated contingencies’ wording is more cryptic and less clear than the previous wording. o Suggestion: Suggest wording more similar to the previous draft, ‘Facilities that if destroyed, degraded, misused, or otherwise rendered unavailable, could cause the violation of one or more IROLs.’<br><br>Criterion 1.10: o We suggest expanding the wording of “loss of the assets” to “loss of more than 1500 MW of assets” to clarify that the inclusion of Transmission Facilities that would result in the loss of more than 1500 MW but less than all of the assets at a single plant location and the exclusion of Transmission Facilities that may result in the loss of less than 1500 MW of the assets at a single plant location. o Added the wording of ‘identified by any Generator Owner as a result of its application of’. Generator Owner would apply Criterion 1.1 and 1.3 to its generating facility, rather than obligate the TO to apply the criteria which and possibly lead to disagreements.<br><br>Criterion 1.11: o This criterion is not clear and distinct because in an ultimate analysis the entire interconnection minus certain selected elements is essential to meeting the NPIRs at any given nuclear facility. o Suggestion: Revise the criterion to, “Transmission Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements”, which is consistent with the |

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| | | former EEI comments. |

**Response**: Thank you for your comments.

The purpose of FAC-014-2 Requirements R3 and R4 is to establish a clear and consistent method for identifying IROLs. The method for Planning to identify IROLs is beyond the scope of the CIP standards.

Criterion 1.3: There is no burden or obligation placed on the Planning Coordinator or Transmission Planner to designate any unit as needed to avoid Adverse Reliability Impacts in the long-term planning horizon. However, if the PC or TP has identified Adverse Reliability Impacts (the impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that

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| affects a widespread area of the Interconnection), then any units identified that avoid this scenario must be classified as a Critical Asset.<br><br>Criterion 1.8: The wording for criterion 1.8 came from FAC-014-2 Requirement R5.<br><br>Criterion 1.10: The SDT believes the phrase "loss of the assets identified by any Generator Owner as a result of its application of Attachment 1, criterion 1.1 or 1.3" contained in the balloted version of CIP-002-4 conveys the same intent as your proposed language.<br><br>Criterion 1.11: Criterion 1.11 is based on NUC-001-2 R9.2.2 "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." | | |
| Basin Electric Power Cooperative | | Attachment #1, Criterion 1.1 needs to have "in a single interconnection" added to the end. The Laramie River Station in Wheatland, Wyoming is a three generator station with two 550 MW generators in the Western Interconnection and one 550 MW generator in the Eastern Interconnection. (there doesn't appear to be any specific place to submit substantative comments on the standard) |
| **Response**: Thank you for your comments. The SDT has incorporated your suggested wording in Attachment 1 Criterion 1.1. | | |
| Pepco Holdings Inc and Affiliates | Yes | Attachment 1 Critical Asset CriteriaItem 1.1-- Please clarify the process that the Transmission Owner would find out about Generator Owners or Generator Operator facilities identified under Item 1.3. Suggest have some statement similar to 1.3 regarding informs. Should the Planning Coordinator or Transmission Planner not only designate and inform the Generator Owner or Generator Operator but the Transmission Owner?General-- Please take steps to reduce ambiguous language. (e.g. black start resources). |
| **Response**: Thank you for your comments.<br><br>Criterion 1.3: The process would be that the Planning Coordinator or Transmission Planner would notify the Generation Owner and Generation Operator about any facilities that meet Criterion 1.3. The GO and/or GOP would need to notify the Transmission Owner of any facilities that need to be considered for Criterion 1.10.<br><br>The SDT has made efforts to reduce any ambiguous language. In your example the SDT chose the NERC glossary term "Blackstart Resources" in | | |

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| order to eliminate any confusion over the term. | | |
| BGE | Yes | BGE thanks the SDT for their positive response to the previously submitted comments. BGE asks that the SDT consider adding to the Guidance Document the reasoning behind the 300 MW criteria listed in the automatic load shedding criteria 1.13 in Appendix 1. |
| **Response**: Thank you for your comments. The posted Guidance document has been modified to add reasoning for the threshold level. | | |
| Bonneville Power Administration | No | BPA believes that the bright line criteria approach in CIP-002-4 is an improvement over prior versions. However, it still does not address the concern by the industry in regards to providing sufficient clarity to many portions of CIP-002-4 to make it acceptable to the majority of utilities that must understand and develop strategies to meet the standards and requirements and implement them in a reasonably timely fashion. BPA still supports the formal comments that we submitted in October 2010. See additional comments below:<br><br>CIP-002-4 R2.1. “The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter” does not go far enough in its definition of what qualifies as a critical cyber asset and needs further clarification, particularly concerning serial devices. For example: What exactly is meant by "uses a routable protocol to communicate outside the Electronic Security Perimeter"?<br><br>1. Can a device that is not capable of native routable protocol (does not have, or use an ethernet card) qualify as using routable protocol? 2. Does a device that is not capable of native routable protocol, that is connected to a device which is ethernet connection outside the ESP (Serial to Ethernet Converter) qualify? 3. Does a device that is not capable of native routable protocol, but is connected to a Terminal Server, which is ethernet connected outside the ESP qualify?4. Does it make a difference if there is only view access to the internal ESP device with no possible ability to control it?5. What if the device |

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| | | is connected to another device which is ethernet connected, but it simply dumps to a data-store on that device, and there is no access through to the data-store device (the internal ESP device)?6. What if the device itself never initiates communications outbound, and can only be connected to if access is initiated to it from elsewhere?7. What if the device has no ability to connect to and influence any other device?8. What if you can't connect to that device and through it connect to any other device?9. What if the Serial to Ethernet device between the Cyber Asset and the network strips all routable protocol information off and forwards only non-routable data to the Cyber Asset.<br><br>Comments from October 2010:<br><br>Mapping Document - The individual utility's development and implementation of their risk-based methodology instills ownership in their process and is a positive result of the current CIP versions. For BPA, application of the bright-line assessment criteria for Critical Asset identification in the recent NERC data request resulted in fewer assets being classified in the high impact categorization. However, we see that if a utility's implementation of the criteria resulted in more Critical Assets being identified with the corresponding implementation of security controls at those assets, then an improvement in reliability would occur.<br><br>Attachment 1 - Make it clear that substations are the facilities to be identified as Transmission Critical Assets, not lines, transformers, reactive equipment, etc. Another alternative would be to identify all facilities that operate at a specified certain kV level would be determined to be Critical Assets. The different categories identified in Attachment 1still allow utilities to justify most of what they have already declared as Critical Assets.<br><br>R1 - We agree with the "at least annually" aspect of the requirement. Annual review seems appropriate if a utility has not had any major changes or expansion to their grid since their last Critical Asset determination.<br><br>R2 - The requirement as written continues and does not solve the ambiguity with the current Critical Cyber Asset identification requirement. Specifically: "essential to the operation of the Critical Asset" needs to be defined; "adversely impact the reliable operation" needs to be defined; and, it is not clear what "within 15 minutes" means in this context. The intent of the Standards Drafting Team needs to be |

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| | | made clear.<br><br>Implementation Plan - If this version requires more substations to be identified as Critical Assets, then we believe that the proposed implementation is too aggressive. Physical Security Perimeters are expensive and it may not be possible to fund these modifications in the short timeframe for compliance. A 3-year implementation period would be more appropriate. BPA agrees with the proposed revisions to the implementation plan for newly identified CCAs and Responsible Entities. |

**Response**: Thank you for your comments

Requirement R2: This language has existed in versions 1 through 3 of CIP-002. The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. Also, please refer to the "Identifying Critical Cyber Assets" document for additional clarification.

Mapping Document - While some entities may have a few assets fall off of its Critical Asset list, it is expected that overall more BES assets in North America will be classified as Critical Assets.

Attachment 1 - Substations are not the only Facilities identified as Critical Assets. Lines, transformers, reactive equipment, and other Facilities can be classified as a Critical Asset if they meet any of the criteria in Attachment 1. Please refer to the posted guidance document for additional clarification.

R2 - The scope of changes to this Standard only addresses the near-term issues associated with external oversight and review of the risk-based assessment methodology. The subjectivity involved in the Critical Cyber Asset identification requirement will be addressed in future releases of these Standards. The 15 minute threshold is intended to include only those assets at generating units affecting real-time operations. This qualifier is particularly important to a generating plant because several systems (i.e. a fuel-handling system) may be essential after a longer period of time but do

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| not necessarily involve real-time reliability impact.<br><br>Implementation Plan - The SDT believes there is precedent showing this implementation period is reasonable. Upon FERC Approval, the Responsible Entity has a minimum of 2 years to become compliant with new Critical Cyber Assets. This period is consistent with the implementation plan for version 1 of the CIP Cyber Security Standards and the implementation plan for Registered Entities identifying their first Critical Cyber Asset. | | |
| Brazos Electric Power Cooperative, Inc. | No | Brazos Electric appreciates the work of the SDT and is supportive of the efforts and the general concepts of this draft. This is a negative vote due to disagreement over some elements in Attachment 1 criterion as provided below.<br><br>1.3 The term "long-term planning horizon" is referenced but is not clear within the Standard what it means or that it is defined elsewhere.<br><br>1.5 This criterion should be clarified by changing the words "first interconnection point of the generation unit(s)to be started" to be "interconection point to the first generation unit(s)to be started".<br><br>1.6 This criterion should have another factor based on the size of the facility such that loss of the Facility would have an adverse impact on the BES.<br><br>1.7 This criterion should have another factor based on the size of the facility such that loss of the Facility would have an adverse impact on the BES.<br><br>1.13 Consider re-wording of this criterion as follows to better intent. “Each system or Facility that performs automatic load shedding as required by regional load shedding programs that implement Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) of 300 MW or more without human operator initiation.”<br><br>1.15 This criterion should be clarified to define what the term "control" means. It is not clear within the |

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| | | Standard what it means or that it is defined elsewhere. |

**Response**: Thank you for your comments.

Criterion 1.3 - The resource document “Time Horizons” (found at http://www.nerc.com/files/Time_Horizons.pdf) was used to determine the long-term planning horizon. In this document, long-term planning is defined as “a planning horizon of one year or longer”

Criterion 1.5 - The SDT appreciates the suggestion, but believes the posted wording is adequate.

Criterion 1.6 - The SDT will take this suggestion under consideration for future revisions.

Criterion 1.7 - The SDT will take this suggestion under consideration for future revisions.

Criterion 1.13 - The SDT appreciates the suggestion, but believes the posted wording is adequate.

Criterion 1.15 - From the posted Guidance document: “A control center or generation control center that provides critical operating functions and tasks as identified in CIP–002 must be protected per the requirements of the Cyber Security Standard. The monitoring and operating control function includes controls performed automatically, remotely, manually, or by voice instruction.”

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| Central Lincoln | No | Central Lincoln supports the following APPA CIP Task Force comments. If this issue is addressed as suggested, we will vote affirmative on the next ballot. The APPA CIP Task Force has identified what we believe to be an unintended consequence - a Catch-22 - from the interaction of the revised CIP-002-4 Attachment 1's Criteria 1.4 (Blackstart Resources) and 1.5 (identified Cranking Paths) with the control center size and facility exceptions in 1.15, 1.16 and 1.17. This interaction will cause many if not all registered TOPs, BAs and Generation Owners that control Blackstart Resources used in a TOP restoration plan to become subject to CIP-002 through CIP-009, regardless of entity size.EOP-005 requires all TOPs to have a restoration plan. APPA's reading of EOP-005 indicates that each TOP must identify one or more Blackstart Resources. CIP-002-4 Criterion 1.4 requires a TOP to identify each such Blackstart Resource identified in its restoration plan as a critical asset. Criterion 1.5 requires the identification of certain Cranking Paths as critical assets.Criterion 1.15 requires that each generation control center or backup control center used to control a Blackstart Resource identified under Criterion 1.4 be identified as a critical asset, without any exception for generation control center size (1500 MW).Criterion 1.16 requires each transmission control center or backup control center used to control a Cranking Path identified under Criterion 1.5 be identified as a critical asset, without any exception for TOP control center size.Criterion 1.17 requires each Balancing Authority control center or backup control center used to control a Blackstart Resource identified under Criterion 1.4 be identified as a critical asset, without any exception for Balancing Authority control center size (1500 MW).In effect, Criterion 1.4 swallows all exceptions created under 1.15 through 1.17, with the possible exception of a generation-only BA that does not have any Blackstart Resource obligations to its TOP. All vertically integrated utilities would be responsible for CIP-002 through CIP-009, including small BAs and TOPs that do not own any other Critical Assets.To address this problem, we propose the following edits to 1.4 and 1.5 shown in CAPS:1.4. Each Blackstart Resource identified in the RESTORATION PLAN FOR A Transmission Operator SERVING LOAD OR GENERATION EQUAL TO OR GREATER THAN AN AGGREGATE OF 1500 MW IN A SINGLE INTERCONNECTION. 1.5. The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart |

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| | | Resource(S) IDENTIFIED IN 1.4. to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist, as identified in the Transmission Operator's restoration plan. This surgical approach ensures that generation, TOP and BA control centers with responsibility for other critical generation and transmission assets are still responsible for full CIP-002-4 through CIP-009 compliance. However, small BA/TOP systems with no initial obligations to the RC and larger TOPs for regional restoration would not be deemed “critical.” The experience of these smaller systems is that their restoration obligations have not been relied upon to restore the BES, but rather to start generation to serve local load after a system separation - and then to wait for direction from the RC on resynchronization with the rest of the BES, once voltage and frequency are stabilized. While we recognize that cyber events may have an impact on the availability of resources, the fundamental fact is the vast majority of Blackstart Resources and control centers will be protected under CIP-002 through -009, because they will be classified as Critical/High Impact under the proposed criteria, as revised above. Thus the revised criteria support rather than undermine the distinction between categorization of big iron/big aluminum resources and their associated control centers as Critical or High Impact in the development of CIP-002-4. The categorization and development of security controls for smaller resources as either medium or low impact for the BES, should be addressed through development of additional bright line criteria and associated security controls in the next phase of this project (CIP-002-5 or CIP-010/011.) |

**Response**: Thank you for your comment.

The SDT carefully selected criteria around the NERC Glossary term Blackstart Resource and its derivation from EOP-005-2. It was felt that these resources are critically important in their function to restore the BES under blackstart conditions. As such, these assets deserve protection as a Critical Asset. Due to their connectivity and configuration, control centers that operate these Blackstart Resources also have the ability to jeopardize their availability and function in a time of need if maliciously misused. As such, these control centers should also be deemed Critical Assets. The SDT appreciates the "catch-22" concern that was brought forth by APPA. However, the SDT does not believe that the criteria as written present a catch-22 scenario. A careful reading of EOP-005-2 indicates that those assets identified as Blackstart Resources are those needed to bring the shutdown area "to a state whereby the choice of Load to be restored is not driven by the need to control frequency or voltage." The APPA comments indicate that the assets of concern to them are being utilized "once voltage and frequency are stabilized." As such, these assets are not required to be included in the TOP's restoration plan as Blackstart Resources. Additionally, it should be noted that EOP-005-2 does not presume that Blackstart Resources are only those "located within the Transmission Operator’s System." As such, smaller TOPs have the opportunity to coordinate with

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| neighboring TOPs and the RC in the development of their restoration plan which may not necessarily identify Blackstart Resources in their own system. In light of these clarifications, the SDT does not believe that a catch-22 exists that would unnecessarily bring in all TOP/BA control centers regardless of size, but rather only those that have the potential to impact Blackstart Resources that are essential to BES restoration as identified through EOP-005-2. | | |
| City Utilities of Springfield, Missouri | No | City Utilities of Springfield, Missouri believes that the proposed bright-line criteria will improperly identify lower impact Blackstart Resources as Critical Assets. City Utilities agrees with the comments submitted by the APPA Task Force. |
| **Response**: Thank you for your comments. Please refer to the response to APPA's Task Force contained in Central Lincoln's comments. | | |
| San Diego Gas and Electric | Yes | Comment on 1.8, 1.9, 1.10: There should be some obligation that the parties that identify the Transmission Facility as critical (e.g. RC, PA, TP, GO) that they also notify the Transmission Owner and Operator of that identification so the TOP and TO are aware and can protect.Comment on 1.8, 1.9: What does the statement "critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" mean? |
| **Response**: Thank you for your comments.<br><br>Criterion 1.8 and 1.9 - FAC-014-2 R5 contains all of the information concerning communication of Facilities that are critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.<br><br>Criterion 1.10 – It is agreed that communication between Generator Operators and Transmission Owners and Transmission Operators will be required to ensure that all Critical Assets are identified.<br><br>The wording for 1.8 and 1.9 came from FAC-014-2 Requirement R5. | | |

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| Electric Market Policy | Yes | Dominion supports the latest revision of CIP-002-4 through CIP-009-4 (excluding CIP-005-4) |
| **Response**: Thank you for your comments. | | |
| FirstEnergy | Yes | FirstEnergy agrees that the standard drafting team's changes to the proposed CIP-002-4 reliability standard have been responsive to industry feedback and believe the team's work will drive further consensus. While FE has voted in support of the standard, we offer the following comments as clarifying revisions permitted by the NERC Process Manual prior to a Recirculation (Final) Ballot.A) Applicability to nuclear generation. The proposed revisions regarding exemption language for nuclear generation plants located in the United States (U.S.) along with the parenthetical text of Attachment 1 criterion stating "including nuclear generation" leaves the standard ambiguous and in need of clarification based on recent Nuclear Regulatory Commission (NRC) findings. The NRC and NERC have worked closely to address FERC's Order 706B concerns related to any nuclear balance of plant (BOP) systems, structures and components (SSCs) within a U.S. nuclear power plant that is not regulated by the NRC and subject to NERC CIP standards. However, the NRC letter to NERC dated November 26, 2010 clarifies its findings that "Based on the Commission's [NRC] determination, the NRC staff does not believe that there will be any SSCs in the BOP that will fall under NERC's Critical Infrastructure Protection (CIP) standards." While the letter acknowledges that there may be some SSCs in a nuclear plant that are not subject to the NRC's cyber security regulations or NERC's CIP standards, the NRC indicates "these SSCs do not have a nexus to radiological health and safety and do not affect grid reliability." Based on the NRC's November 26, 2010 FE believes that NERC should retain the original exemption language related to U.S. nuclear plants in section 4.2 of the standard and remove the parenthetical text "including nuclear generation" from the Attachment 1 criteria 1.1.B) Attachment 1, Criterion 1.6. Item 1.6 currently reads "Transmission Facilities operated at 500 kV or higher." For consistency with other Attachment 1 criteria we propose that this criterion be revised to read "Transmission Facilities at a single station or substation location operated at 500kV or higher". This change clarifies that the intent is to classify the 500kV substation as a Critical Asset and not individual transmission lines that terminate at the substation.<br><br>C) Attachment 1, Criterion 1.8. FirstEnergy suggests that the Reliability Coordinator be removed |

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| | | from the criterion that identifies Critical Asset facilities based on Interconnection Reliability Operating Limits (IROLs). For consistency with criterion 1.3 which identifies Critical Asset generation necessary to avoid BES Adverse Reliability Impacts in the "long-term planning horizon" we propose that the Critical Assets identified based on IROL also be limited to the study of the Planning Coordinator and the Transmission Planner in the long-term planning horizon. The Reliability Coordinators role in real-time conditions for IROL are generally aimed at fine tuning the appropriate operating limits that they monitor based on actual system conditions and would typically not identify any new "facilities" associated with an IROL. In the unlikely event that a Reliability Coordinator would identify a very unique IROL condition not identified by the rigorous study work of a Planning Coordinator or Transmission Planner it would be for extremely unique and temporary system conditions and would not warrant long-term Critical Asset determinations. |
| **Response**: Thank you for your comments.<br><br>Nuclear generation applicability - The phrase "including nuclear generation" in Criterion 1.1 is there to define a plant site. Unit output from all units at a single plant site should be included to determine if a plant meets the 1500MW threshold. The evaluation for Critical Cyber Assets is similar. Although it is highly unlikely that nuclear and non-nuclear units share common Cyber Assets, the evaluation should still occur.<br><br>Criterion 1.6 – The purpose of classifying Critical Assets is to identify all Critical Cyber Assets. While it is true that almost all Critical Cyber Assets associated with 500kV Facilities are located inside of a substation, the potential exists for it to not be located there. If a Critical Cyber Asset is not located within the bounds of a station or substation, it must still be protected from cyber attacks.<br><br>Criterion 1.8 – According to FAC-014-2 Requirement R1 "The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology." Since they have a responsibility to ensure that the IROLs are established and consistent with their SOL methodology, it is valid to list them in this Criterion. | | |
| Tacoma Power | Yes | For Criterion 1.13, the term "System" is defined in the NERC Glossary of Terms but is not capitalized. I suggest that a change be made to capitalize the word System. |
| **Response**: Thank you for your comments. The term "system" can refer to systems other than "a combination of generation, transmission, and | | |

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| distribution components." The SDT believes it is correct to refer to "system" instead of "System." | | |
| City of Grand Island | No | General Comment: So many items give one entity the power to designate facilities owned by another entity as critical. Yet there is no mention of justification and no process to mediate differences of opinion. Specific Comments:<br><br>1.3 This criteria should have a MW level. Suggest: "Each Blackstart Resource identified in the restoration plan for a Transmission Operator serving load or generation equal to or greater than 1500 MW."<br><br>1.4 Reference Blackstart Resourses identified in 1.4 (see above modified 1.4). |
| **Response**: Thank you for your comments.<br><br>The issue of communication between entities is recognized as an issue that needs to be addressed and will be considered in a future version.<br><br>Criterion 1.4 - Thank you for your comment. The SDT carefully selected criteria around the NERC Glossary term Blackstart Resource and its derivation from EOP-005-2. It was felt that these resources are critically important in their function to restore the BES under blackstart conditions, regardless of MW capability. As such, these assets deserve protection as a Critical Asset. | | |
| Pinellas County Resource Recovery Facility | Yes | I think the bright-line criteria provide much needed consistency and give beneficial direction to registered entities in identifying their critical assets. |
| **Response**: Thank you for your comment. | | |

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| Independent Consultant | Yes | In CIP-002-4 Attachment 1 Criteria items 1.15 & 1.17 contain two criteria each. The first criteria in each of these statements if based on 'functionality', and the second criteria is based on 'span of control' (> 1500MW). It would appear that a separate criteria for span of control should be listed and that aspect of the criteria removed from 1.15 & 1.17.Suggested separation provided below. Criteria numbering would need to be adjusted appropriately.1.14. Each control center or backup control center used to perform the functional obligations of the Reliability Coordinator. 1.15. Each control center or backup control center used to control generation at multiple plant locations, for any generation Facility or group of generation Facilities identified in criteria 1.1, 1.3, or 1.4.NEW: Each control center or backup control center used to control generation equal to or exceeding 1500 MW in a single Interconnection. 1.16. Each control center or backup control center used to perform the functional obligations of the Transmission Operator that includes control of at least one asset identified in criteria 1.2, 1.5, 1.6, 1.7, 1.8, 1.9, 1.10, 1.11 or 1.12. 1.17. Each control center or backup control center used to perform the functional obligations of the Balancing Authority that includes at least one asset identified in criteria 1.1, 1.3, 1.4, or 1.13. NEW: Each control center or backup control center used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection. |

**Response**: Thank you for your comment. The SDT decided to group the criteria for control centers based on functionality. Separating then does not appear to add any additional clarity to the criteria.

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| Luminant | Yes | Luminant thanks the SDT for their work on the standard and for the opportunity to provide comments for consideration by the SDT. Luminant believes the changes to CIP-002-4 are responsive to the concerns expressed by the industry and provide acceptable bright-line criteria for the determination of Critical Assets.<br><br>Luminant does request the SDT to consider a wording change in the "Draft Guidance Document". On page 10 of the Clean version of the document, in reference to Special Protection Schemes, the following is listed:"Part 1.12 designates Special Protection Systems and Remedial Action Schemes as Critical Assets. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time they are required or if they operate outside of the parameters they were designed for. Generation Owners and Operators which have implemented such systems and schemes must designate them as Critical Assets. " The term "implemented" is not consistent with other NERC standards and can lead to disagreements on who is responsible for the Critical Asset CIP requirements. Luminant asks the SDT to change the language to: "Generator Owners and Operators that own such systems and schemes...." The term "own" is consistent with other NERC standards that are applicable to Special Protection Systems and Remedial Action Schemes, and very clearly identifies the responsible entity. Thank you for your consideration of our comments. |
| **Response**: Thank you for your comments.<br><br>Your suggested change to the Guidance document has been made. | | |
| Minnesota Power | No | Minnesota Power believes that CIP-002-4 R1 needs to clearly state "The RE should identify a list of Critical Asset that it owns..." While the Standard Drafting Team did speak to this in its response to the California ISO's comments, the SDT did not go far enough to eliminate potential interpretation issues in the future. Specifically, there is ambiguity as to what this would mean from a Balancing Authority perspective. The "its assets" language as written could be interpreted to mean the assets it controls, rather than those assets it owns. As such, we would urge the Standard Drafting Team to reconsider, and include a stronger ownership statement in the proposed standard language. |

| Organization | Yes or No | Question 1 Comment |
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| **Response**: Thank you for your comment. The drafting team believes the phrase “a list of its identified Critical Assets” in R1 specifies ownership of the Critical Asset by the Responsible Entity. | | |
| PPL Electric Utilities Corporation | Yes | PPL Electric Utilities Corporation (“PPL EU”) appreciates the hard work and efforts of the Standards Drafting Team in reaching this point in the standards development process. However PPL EU has reviewed the CIP-002-4 standard version dated 11/30/2010 and the associated Rationale and Implementation Reference Document and Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities and still find the need to offer comments as follows:<br><br>1) CIP-002-4, Attachment 1, Criterion 1.1 should include a requirement that the Generator Owner or Generator Operator must inform the Transmission Operator, Transmission Operator, Planning Coordinator or Transmission Planner of each group of generating units that has been designated as a critical asset.<br><br>2) CIP-002-4, Attachment 1, Criterion 1.3 should be reworded to indicate "Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator, "and the Transmission Owner and Transmission Operator" as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.<br><br>3) CIP-002-4, Attachment 1, Criterion 1.5 should be reworded to indicate "The facilities comprising the Cranking Paths and Meeting the initial switching requirements from the Blackstart Resource “up to and including” the first interconnection point of the generation unit(s) to be started, or up to “and including” the point on the Cranking Path where two or more path options exist "including the first interconnection point of the generation unit(s) to be started" , as identified in the Transmission Operator's restoration plan.<br><br>4) CIP-002-4, Attachment 1, Criterion 1.13 should be revised to include load shed systems capable of shedding 300 MW or more. These load shed systems, which are typically part of the energy management systems, are initiated to ensure the reliability of the BES.<br><br>5) CIP-002-4, Attachment 1, Criterion 1.13 should be reworded to indicate that distributed UFLS or UVLS schemes (i.e., individual UF or UV relays operating independently in multiple substations) are |

| Organization | Yes or No | Question 1 Comment |
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| | | not considered to be a critical asset. Collectively the UFLS or UVLS scheme may shed more than 300MW; however, due to the distributed nature of the scheme, the UFLS or UVLS schemes are not considered to be a critical asset. |

**Response**: Thank you for your comments.

Criterion 1.1 - It is agreed that communication between Generator Operators and Transmission Owners and Transmission Operators will be required to ensure that all Critical Assets are identified.

Criterion 1.3 - The process would be that the Planning Coordinator or Transmission Planner would notify the Generation Owner and Generation Operator about any facilities that meet Criterion 1.3. The GO and/or GOP would need to notify the Transmission Owner of any facilities that need to be considered for Criterion 1.10.

Criterion 1.5 - The SDT appreciates the suggestion, but believes the posted wording is adequate.

Criterion 1.13 – A discrete component that sheds more than 300MW of load due to the implementation of Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program is a Critical Asset. During the previous ballot and comment period, the SDT received many comments on this criterion, whose wording was similar to this suggestion. Some commenters stated that the wording of this criterion will inadvertently bring in all SCADA systems with the capability of shedding load even if such SCADA systems are in fact not planned or operated to perform load shedding. This was not the intent of the SDT. Other commenters stated that this item needs to be clarified to confirm that it applies to a single common control system only, and not multiple but separate “like” systems that in aggregate are capable of load shedding up to 300 MW. Also, the criterion needs to be clarified to confirm that it applies to systems “configured” for automatic load shedding, not simply just “capable” of load shedding. This criterion was intended to include as Critical Assets regional Under Frequency Load Shedding and Under Voltage Load Shedding schemes. The SDT appreciates the suggestion, but believes the posted wording is correct.

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| Southern Company Transmission | Yes | Southern believes that the SDT's changes to the proposed standard were responsive to some of the feedback received; however, certain key industry comments still have not been adequately addressed. For example, in Attachment 1, Section 1.11 should be deleted. Section 1.11 relates to Transmission Facilities necessary to secure offsite power to permit safe reactor shutdown. Although such Transmission Facilities are within the scope of Nuclear Plant Interface Coordination standards (NUC reliability standards), they are not within the intended scope of the Cyber Security standards (CIP reliability standards). The Purpose section of the NUC reliability standards states "This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown." The Purpose section of the CIP reliability standards states "NERC Standards CIP-002-4 through CIP-009-4 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System." Therefore, Section 1.11 should be deleted because it is clearly out of scope. Moreover, the criticality of facilities for BES reliability purposes should not be based on fuel type alone.<br><br>In addition, Southern believes the following proposed changes made by the SDT should be reconsidered: In Attachment 1, Section 1.10, the SDT deleted the word "directly" by changing "generation interconnection required to directly connect generator output" to "generation interconnection required to connect generator output." The word "directly" should not be deleted from Section 1.10 because it is necessary to appropriately define the scope of the requirement. Removing the word "directly" removes the bright line criteria, which is the goal of the new standard. As proposed by the SDT, the standard would require various risk-based analyses i.e. load flow and transient stability studies to determine the assets in scope. Therefore, the SDT should reconsider this proposed change.<br><br>The proposed Section 1.13 would be clearer if it were changed to the following: "1.13. Each system or facility that implements Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) of 300 MW or more without human operator initiation as required by the regional load shedding program." |

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**Response**: Thank you for your comments.

Criterion 1.11 – This criterion is based on NUC-001-2 R9.2.2 "Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs." Since these facilities were deemed so important that a NERC reliability standard was written and adopted to clarify the issue, the SDT determined that this was adequate justification to include them as Critical Assets. While the purpose of NUC-001-2 states "This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown," it is a NERC reliability standard and as such helps to ensure the reliability of the Bulk Electric System.

Criterion 1.10 - Several commenters in the first posting were concerned about the use of the term "directly." After consideration by the Standard Drafting Team, it was determined that the term could be removed without affecting the intent of the criterion.

Criterion 1.13 - The SDT appreciates the suggestion, but believes the posted wording is adequate.

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| MRO's NERC Standards Review Subcommittee | No | The MRO NSRS believes the SDT was responsive to much of the feedback received from the industry; however, we question whether these bright-line criteria as a whole are acceptable for determining Critical Cyber Assets. We believe the following criteria need to be adjusted as follows to properly address these areas:<br><br>Attachment 1, Criterion 1.4We believe EOP-005-2, which defines the Transmission Operator restoration plan and related Blackstart Resource requirements, is ambiguous as to what actually constitutes a Blackstart Resource. For example, assume a plant has a 1 MW diesel engine that is used to start a 100 MW combustion turbine when the system is black. What is the Blackstart Resource, the 1 MW diesel engine or the 100 MW combustion turbine? To our knowledge, EOP-005-2 does not answer this question. Even at the regional restoration plan level, we believe many utilities are currently designating the 1 MW diesel engine as the Blackstart Resource under EOP-005-2, whereas others have designated the 100 MW combustion turbine. We realize this appears to be more of an issue with EOP-005-2, and not CIP-002-4. However, the effect of this EOP-005-2 ambiguity will be greatly magnified once CIP-002-4 begins using this same designation to identify critical assets, determining where an entity focuses their time and resources related to cyber security. For this reason, we believe the CIP-002-4 and EOP-005-2 SDT's must work together to clarify this designation, enabling us to apply the definition of a Blackstart Resource, and the related cyber security efforts, uniformly across the industry.<br><br>Attachment 1, Criteria 1.4 & 1.5The APPA has identified an issue where criteria 1.4 and 1.5 end up requiring nearly all control centers to be identified as critical, even for small entities. The MRO NSRS recognizes this unintended consequence, and supports the following APPA comments: "The APPA CIP Task Force has identified what we believe to be an unintended consequence - a Catch-22 - from the interaction of the revised CIP-002-4 Attachment 1's Criteria 1.4 (Blackstart Resources) and 1.5 (identified Cranking Paths) with the control center size and facility exceptions in 1.15, 1.16 and 1.17. This interaction will cause many if not all registered TOPs, BAs and Generation Owners that control Blackstart Resources used in a TOP restoration plan to become subject to CIP-002 through CIP-009, regardless of entity size. EOP-005 requires all TOPs to have a restoration plan. APPA's reading of EOP-005 indicates that each TOP must identify one or more Blackstart Resources. CIP-002-4 Criterion 1.4 requires a TOP to identify each such Blackstart Resource identified in its restoration plan as a |

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| | | critical asset. Criterion 1.5 requires the identification of certain Cranking Paths as critical assets. Criterion 1.15 requires that each generation control center or backup control center used to control a Blackstart Resource identified under Criterion 1.4 be identified as a critical asset, without any exception for generation control center size (1500 MW). Criterion 1.16 requires each transmission control center or backup control center used to control a Cranking Path identified under Criterion 1.5 be identified as a critical asset, without any exception for TOP control center size. Criterion 1.17 requires each Balancing Authority control center or backup control center used to control a Blackstart Resource identified under Criterion 1.4 be identified as a critical asset, without any exception for Balancing Authority control center size (1500 MW). In effect, Criterion 1.4 swallows all exceptions created under 1.15 through 1.17, with the possible exception of a generation-only BA that does not have any Blackstart Resource obligations to its TOP. All vertically integrated utilities would be responsible for CIP-002 through CIP-009, including small BAs and TOPs that do not own any other Critical Assets. To address this problem, we propose the following edits to 1.4 and 1.5 shown in quotation marks:"1.4. Each Blackstart Resource identified in the RESTORATION PLAN FOR A Transmission Operator SERVING LOAD OR GENERATION EQUAL TO OR GREATER THAN AN AGGREGATE OF 1500 MW IN A SINGLE INTERCONNECTION. 1.5. The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource(S) IDENTIFIED IN 1.4. to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist, as identified in the Transmission Operator's restoration plan." This surgical approach ensures that generation, TOP and BA control centers with responsibility for other critical generation and transmission assets are still responsible for full CIP-002-4 through CIP-009 compliance. However, small BA/TOP systems with no initial obligations to the RC and larger TOPs for regional restoration would not be deemed "critical." The experience of these smaller systems is that their restoration obligations have not been relied upon to restore the BES, but rather to start generation to serve local load after a system separation - and then to wait for direction from the RC on resynchronization with the rest of the BES, once voltage and frequency are stabilized. While we recognize that cyber events may have an impact on the availability of resources, the fundamental fact is the vast majority of Blackstart Resources and control centers will be protected under CIP-002 through -009, because they will be classified as Critical/High Impact under the proposed criteria, as revised above. Thus the revised criteria support rather than undermine the distinction between categorization of big iron/big aluminum resources and their associated control |

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| | | centers as Critical or High Impact in the development of CIP-002-4. The categorization and development of security controls for smaller resources as either medium or low impact for the BES, should be addressed through development of additional bright line criteria and associated security controls in the next phase of this project. (CIP-002-5 or CIP-010/011)"<br><br>Attachment 1, Criterion 1.10If a generating facility that falls under the brightline of criterion 1.1 has numerous Transmission Facilities providing interconnections to the system, all of them would be designated as critical under criterion 1.10, even if their loss does not result in the loss of at least 1500 MW of generation. To prevent this, we would propose rewording the criterion as follows:"Transmission Facilities providing the generation interconnection required to connect generator output to the transmission system that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in THE LOSS OF AT LEAST 1500 MW OF GENERATION ASSETS IDENTIFIED BY AN GENERATOR OWNER AS A RESULT OF ITS APPLICATION OF ATTACHMENT 1, CRITERION 1.1, OR the loss of the assets identified by any Generator Owner as a result of its application of Attachment 1, criterion 1.3."<br><br>Attachment 1, Criterion 1.13We are concerned that as currently worded, this criterion could unintentionally designate multiple smaller, disparate systems with like settings as a "system" that performs automatic load shedding of 300 MW or more, assuming the total combined load shedding capability of the disparate systems exceeds 300 MW. To prevent this, we would propose rewording the criterion as follows to more closely match the old version:"Each COMMON system or Facility that performs automatic load shedding, without human operator initiation, of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program."<br><br>Attachment 1, Criterion 1.15Even if a small utility, as a joint owner, has control over only a small portion of a large plant that falls under the brightline of criterion 1.1, we are concerned that as currently written, the first sentence of criterion 1.15 would unintentionally designate this small utility's control center as critical. To prevent this, we would propose rewording the criterion as follows:"Each control cen |

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**Response**: Thank you for your comments

Criterion 1.4 - A Blackstart Resource is defined as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator’s restoration plan.” It is difficult to imagine a scenario in which a 1 MW generator can fulfill all of the requirements in the Blackstart Resource definition. However, any generator designated a Blackstart Resource per EOP-005-2 must be classified a Critical Asset.

The SDT carefully selected criteria around the NERC Glossary term Blackstart Resource and its derivation from EOP-005-2. It was felt that these resources are critically important in their function to restore the BES under blackstart conditions. As such, these assets deserve protection as a Critical Asset. Due to their connectivity and configuration, control centers that operate these Blackstart Resources also have the ability to jeopardize their availability and function in a time of need if maliciously misused. As such, these control centers should also be deemed Critical Assets. The SDT appreciates the "catch-22" concern that was brought forth by APPA. However, the SDT does not believe that the criteria as written present a catch-22 scenario. A careful reading of EOP-005-2 indicates that those assets identified as Blackstart Resources are those needed to bring the shutdown area "to a state whereby the choice of Load to be restored is not driven by the need to control frequency or voltage." The APPA comments indicate that the assets of concern to them are being utilized "once voltage and frequency are stabilized." As such, these assets are not required to be included in the TOP's restoration plan as Blackstart Resources. Additionally, it should be noted that EOP-005-2 does not presume that Blackstart Resources are only those "located within the Transmission Operator’s System." As such, smaller TOPs have the opportunity to coordinate with neighboring TOPs and the RC in the development of their restoration plan which may not necessarily identify Blackstart Resources in their own system. In light of these clarifications, the SDT does not believe that a catch-22 exists that would unnecessarily bring in all TOP/BA control centers regardless of size, but rather only those that have the potential to impact Blackstart Resources that are essential to BES restoration as identified through EOP-005-2.

Criterion 1.10 - The intent is to ensure the availability of Facilities necessary to support those generation Critical Assets. Any Transmission Facility that the loss of which would result in the loss of a Critical Asset identified in criterion 1.1 or 1.3 would need to be classified as a Critical Asset.

Criterion 1.13 - In the drafting of this criterion, the drafting team sought to include only those systems that did not require human operator initiation, and targeted in particular those Under Frequency Load Shedding (UFLS) facilities and systems and Under Voltage Load Shedding (UVLS) facilities and systems that would be implemented as part of a regional load shedding requirement to prevent Adverse Reliability Impact. It is unclear how adding the term “common” adds any additional clarity over the existing wording. A discrete component that sheds more than 300MW of load due to

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| the implementation of Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by the regional load shedding program is a Critical Asset.<br><br>Criterion 1.15 - The concern here is that the joint owner's control center could provide a path to compromise the functionality of the generation designated as a Critical Asset. | | |
| Manitoba Hydro | No | The SDT addressed some but not all of the issues in the current proposed version of CIP-002-4. Please see Manitoba Hydro's voting recommendation and associated comments for further details. |
| **Response**: Thank you for your comments. | | |
| USACE | No | The Standards Drafting Team still is been prescriptive in determining Critical Assets. The Responsible Entity is responsible for identifying Critical Assets, as pointed out in Order 706, and FERC directed NERC to provide additional guidance in helping the Responsible Entity determine Critical Assets and for NERC to maintain flexibility for the Responsible Entity in the determination of Critical Assets. The prescriptive nature of the approach being used in the Ver 4 CIP Standard appears to be taking the responsibility of determining Critical Assets away from the Responsible Entity and the lack of flexibility may eliminate or preclude a system or component from being identified as a Critical Asset. This process, with out the jpropper full ris assesment to understand what is critical in the BES system, willnot result on a more secure BES. More assets in the list does not translate to more secure overall system. |
| **Response**: Thank you for your comments. The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. The Attachment 1 criteria were developed in response to an external oversight directive in the FERC Order 706. In consideration of this directive, the SDT decided there did not exist across all regions an appropriate third party to provide this type of oversight. Also, external review and oversight carries with it the compliance overhead and arbitration processes analogous to the TFE process. This "bright-line" criteria approach | | |

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| removes the variability of entity defined methodologies that would prompt the need for external review. | | |
| Constellation Energy Commodities Group | No | The team was very responsive to feedback and addressed each comment. However, we do not believe the bright-line criteria to be acceptable - specifically 1.15. Comments were included on the ballot. In addition, we offer the comment below.<br><br>New Language - 1.13 - Each system(s) or facilities that perform automatic load shedding, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) as required by the regional load shedding program. Excluding high-set underfrequency load shedding (“UFR”), as incorporated in the ERCOT Load acting as a Resource (“LaaR”) Demand Response Program, which requires such relay protection. As the trip threshold for UFR is set above that of the regional requirements for the UFLS, the UFR type load shedding should be exempt from this requirement. (This should be clarified in the Guidance Document to maintain a clear scope of intent in the requirement.) |
| **Response**: Thank you for your comment.<br><br>Criterion 1.13 – If the trip threshold for UFR is set above that of the regional requirements for the UFLS, then the Standard Drafting team is unclear how it would be required as part of the regional UFLS program, and thus be classified as a Critical Asset. The “LaaR” is not part of the regional load shedding program, but an ancillary services market. | | |

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| Northeast Power Coordinating Council | No | The wording in the Applicability Section exempts “Facilities regulated by the Canadian Nuclear Safety Commission”, and “Cyber Assets associated with Cyber Security Plans submitted to and verified by the U. S. Nuclear Regulatory Commission pursuant to 10 C.F.R. Section 73.54.” It is stated in 1.1 “(including nuclear generation)...”, contradicting the Applicability section.<br><br>Criteria 1.3 as revised--”Each generation Facility that the Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.” From the NERC Functional Model, the Reliability Coordinator should be the entity to determine the criticality of a generation Facility, based on information it receives from the Planning Coordinator.<br><br>Criteria 1.8 as revised--”Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.” As per the NERC Functional Model, only the Reliability Coordinator develops IROLs, and as such should be the only entity to determine criticality. There is no need to say “substation location”--substation or station will suffice. Where more than one entity is listed (such as Reliability Coordinator, Planning Coordinator, et al., it must be made clear which of those entities is the primary entity. The NERC Functional Model Version 5 identifies a Planning Coordinator, not a Planning Authority. If Planning Coordinator is referred to in the standard, it must be included in the Applicability section. |
| **Response**: Thank you for your comment.<br><br>Criterion 1.1 - The phrase “including nuclear generation” in Criterion 1.1 is there to define a plant site. Unit output from all units at a single plant site should be included to determine if a plant meets the 1500MW threshold. The evaluation for Critical Cyber Assets is similar. Although it is highly unlikely that nuclear and non-nuclear units share common Cyber Assets, the evaluation should still occur.<br><br>Criterion 1.3 – One of the functions identified in the Functional Model is Planning Reliability, which has an identified task of “Evaluate, develop, document, and report on resource and transmission expansion plans for the Planning Coordinator area. Integrate the respective plans, evaluate the impact of those plans on and by adjoining Planning Coordinator’s integrated plans and assess whether the integrated plan meets reliability needs, and, if not, then to report on potential transmission system and resource adequacy deficiencies and suggest or facilitate the process for developing | | |

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| alternative plans to mitigate identified deficiencies." The Functional Entity responsible for that function is the Planning Coordinator, who is "(t)he functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas." Another function in the Functional Model is Transmission Planning, which has an identified task of "Evaluate, develop, document, and report on expansion plans for the Transmission Planner area. Assess whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements." The Functional Entity responsible for that function is the Transmission Planner, who is "(t)he functional entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner area." The Reliability Coordinator, on the other hand, is "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." The focus of Criterion 1.3 is the long-term planning horizon, not real-time.<br><br>Criterion 1.8 - FAC-014-2 Requirement R3 states "The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology." FAC-014-2 Requirement R4 states "The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology." FAC-014-2 Requirement R1 states "The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology." According to FAC-014-2, the Reliability Coordinator does not develop IROLs. They ensure that the IROLs are established, and that they are consistent with their SOL methodology. Planning Authority is referenced because of FAC-014-2 Requirement R3. Also, since the Planning Coordinator would not own any Critical Assets, they are not subject to CIP-002-4 and would not be listed as a Responsible Entity. | | |

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| OGE | Yes | This question was answered "Yes", however the following recommendations for improvement are offered.<br><br>In attachment 1, the threshold for criteria 1.1, needs to be supported by engineering principles and transmission operations knowledge. The current threshold was seemingly driven by the need to increase the number of facilities.<br><br>Attachment 1, criteria 1.4, needs to be focused on the distinct units that, per the Transmission Operator's restoration plan, are used to restore the system. Units meeting the Blackstart Resource definition that are alternate or backup sources should be included in the Transmission Operator's restoration plan, but excluded from the Critical Asset criteria.<br><br>Attachment 1, criteria 1.7, the response to the prior comments included the statement, "It should be noted that connections to generators or generation-only substations are not counted in this Criterion." For an effective bright-line, this needs to be supported within the standard. Reference to a supplemental document, such as the "consideration of comments", will not suffice in a compliance effort. |
| **Response**: Thank you for your comments.<br><br>Criterion 1.1 - The Standard Drafting Team performed an informal survey of the regions and identified what the megawatt value of the reserve sharing would be for various groups. The SDT used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Balancing Authorities in all regions.<br><br>Criterion 1.4 - The SDT carefully selected criteria around the NERC Glossary term Blackstart Resource and its derivation from EOP-005-2. It was felt that these resources are critically important in their function to restore the BES under blackstart conditions, regardless of MW capability. As such, these assets deserve protection as a Critical Asset. A careful reading of EOP-005-2 indicates that those assets identified as Blackstart Resources are those needed to bring the shutdown area "to a state whereby the choice of Load to be restored is not driven by the need to control frequency or voltage."<br><br>Criterion 1.7 – The choice of the phrases “Transmission Facilities” and “transmission stations or substations” was intentional to exclude connections | | |

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| for generators and generation only substations. | | |
| Tampa Electric | Yes | We agree with the proposed language, however if this version does not pass and changes need to be made, we would strongly recommend bright line criteria for Critical Cyber Assets and a CCA identification methodology. In the absence of such criteria and associated methodology we expect inconsistency across entities, and would recommend the language here be modified as follows: “the only Cyber Assets that must be considered are those shared Cyber Assets that could adversely impact the reliable operation of any combination of units via common mode failure that in aggregate exceeds Attachment 1, criterion 1.1 within 15 minutes.” |
| **Response**: Thank you for your comment. The SDT will take your suggested wording under consideration for future revisions. In the absence of such criteria, please refer to the “Critical Cyber Asset Identification Guideline.” | | |

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| Wisconsin Electric Power Company d/b/a We Energies | Yes | We appreciate the diligence of the Standard Drafting Team in reviewing and responding to the comments and feedback provided during the previous ballot, and the changes made to the bright line criteria in Attachment 1 in response to comments and feedback. We strongly support the change to a single implementation timeline of 24 months which will simplify both implementation and audit requirements, and would like to point out the fact that there is a discrepancy in timelines specified in the draft standard and the timelines specified in the draft implementation plan. This discrepancy must be corrected in the final implementation.<br><br>Also, the timeline proposed for CIP-005-4 should coincide with the timeline for the other CIP version 4 standards to further streamline compliance and audit processes.<br><br>We would also like to express concern that, in so much as Criterion 1.1 could result in the identification of generation plant locations with no Critical Cyber Assets, the resulting requirements in Criterion 1.10 could result in expending efforts protecting transmission assets that might not otherwise need to be protected, diverting resources that might be more effectively expended elsewhere.<br><br>Finally, we would like to express concern that the failure to specify a criticality criteria for Blackstart Resources in Criterion 1.4 will result in current blackstart-capable units not being identified as Blackstart Resources. Thank you for your consideration of these comments. |

**Response**: Thank you for your comments.

The flowchart in the implementation plan has been removed.

Your comments on CIP-005-4 will be forwarded to that team.

Criterion 1.10 - The intent is to ensure the availability of Facilities necessary to support those generation Critical Assets. Any Transmission Facility that the loss of which would result in the loss of a Critical Asset identified in criterion 1.1 or 1.3 would need to be classified as a Critical Asset.

Criterion 1.4 - The SDT carefully selected criteria around the NERC Glossary term Blackstart Resource and its derivation from EOP-005-2. It was felt that these resources are critically important in their function to restore the BES under blackstart conditions, regardless of MW capability. As

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| such, these assets deserve protection as a Critical Asset. | | |
| Independent Electricity System Operator | No | We appreciate the Drafting Team's reinstatement of Section 4.2.1 pertaining to the exemption of facilities regulated by the CNSC. We however respectfully reiterate our objection to criteria 1.6 and 1.7. In our view, removal of some of the facilities identified as Critical Assets using these criteria will have no impact on the BES. Their inclusion on the Critical Assets list would therefore be unnecessary The Drafting Team's response to our comment was "The inclusion of a risk-based evaluation by any entity would not meet the objective of uniform application of Critical Asset identification across all entities."We must however point out that Criteria 1.3, 1.8 and 1.9 already allow entities (whether they be the RC, the PC etc.) the discretion to designate/identify as Critical Assets, facilities "necessary to avoid BES Adverse Reliability Impacts" or "critical to the derivation of IROLs". Presumably, these entities doing the "designating" will have a documented methodology and apply it. We therefore advocate a similar approach in the case of Criteria 1.6 and 1.7.We believe the list of relevant transmission facilities developed by the Responsible Entity, should be subject to an impact-based assessment by the Reliability Coordinator who has the wide-area view of the system. If necessary, an additional requirement that requires the RC to have a risk-based assessment methodology and to conduct the assessment should be included. Such an arrangement would be akin to the exemption provisions advocated by FERC in its Final Rule on Revisions to the ERO definition of Bulk Electric System.We therefore propose the following specific wording: 1.6 Transmission facilities operated at 500 kV or higher, unless the annual review performed by the Reliability Coordinator (new requirement) demonstrates that destruction, degradation or unavailability of those assets will have no impact outside the local area and will not cause BES instability, separation, or cascading outages.1.7 Transmission facilities operated at 300 kV or higher at stations interconnected at 300 kV or higher with three or more other transmission stations, unless the annual review performed by the Reliability Coordinator (new requirement) demonstrates that destruction, degradation or unavailability of those assets will have no impact outside the local area and will not cause BES instability, separation, or cascading outages. |

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| **Response**: Thank you for your comment.<br><br>The SDT considered placing various analysis requirements on the Reliability Coordinator. The Functional Model describes the Reliability Coordinator as "The functional entity that maintains the Real-time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." However, the nature of the Critical Asset list is long-term, since implementation of CIP-003 to CIP-009 is up to two years. Based on this, it was determined that the Reliability Coordinator was not an appropriate entity for this analysis. | | |
| Great River Energy | No | We believe that criterion 1.4 and 1.5 of Attachment 1 need to be revised such that they are tied more closely to criterion 1.1 and 1.3, similar to the wording contained in criterion 1.10. We feel that this is necessary due to the fact that a Blackstart Resource's main function is the restoration of critical generation assets. This would create more clarity on the classification of Blackstart Resources and cranking paths as Critical Assets. A revised criterion 1.4 could read: "Each Blackstart Resource identified in the Transmission Operator's restoration plan as being essential to the restoration of a generating unit identified in Attachment 1 criterion 1.1 or 1.3."A revised criterion 1.5 could read: "The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource identified in criterion 1.4 to the first interconnection point of the generation unit(s)...." |
| **Response**: Thank you for your comment.<br><br>The SDT is unsure of your comment "We feel that this is necessary due to the fact that a Blackstart Resource's main function is the restoration of critical generation assets." A careful reading of EOP-005-2 indicates that those assets identified as Blackstart Resources are those needed to bring the shutdown area "to a state whereby the choice of Load to be restored is not driven by the need to control frequency or voltage." The Blackstart Resource should not be limited to those that start other Critical Assets. A similar defense is made for criterion 1.5.<br><br>Criterion 1.4 - The SDT carefully selected criteria around the NERC Glossary term Blackstart Resource and its derivation from EOP-005-2. It was felt that these resources are critically important in their function to restore the BES under blackstart conditions, regardless of MW capability. As such, these assets deserve protection as a Critical Asset. | | |

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| WECC | Yes | We believe that the proposed changes address the direction to develop a bright-line criteria to replace the individual responsible entity methodologies. This approach will lead to more uniformity and consistency across the continent in the identification of Critical Assets. While WECC continues to believe that the bright line Criteria identified in Attachment 1 of CIP-004-2 may lead to identification of fewer Critical Assets by some entities in the West than were identified using the individual methodologies required by the current version of CIP-002, we recognize the need and desire for consistency across the continent. WECC also continues to believe a similar effort in identifying a bright line criteria for Critical CYBER Assets is necessary, and encourages NERC to consider such actions in any future modification to the standard. The language “essential to the operation of the Critical Asset” is subjective and could lead to the same lack of uniformity and consistency in identifying Critical Cyber Assets that drove the changes in identification of Critical Assets. A lack of a uniform and consistent identification of Critical Cyber Assets may prevent the desired level of reliability and security. |
| **Response**: Thank you for your comment. The scope of CIP-002-4 was to address the consistency issues with the Critical Asset identification method. In the absence of such criteria, please refer to the “Critical Cyber Asset Identification Guideline.” | | |
| Midwest ISO | No | We thank the drafting team for their efforts and the progress they have made in improving this standard since the last ballot. While we do believe the drafting team was responsive to the comments previously submitted, we believe a new issue has been identified and an existing issue persists. The standard shifts responsibility for critical asset identification to third parties. For example, criterion 1.3 essentially causes generation owners to rely on Planning Coordinators to identify their critical generators. This responsibility should not be trasnferred and Order 706 was clear that it cannot be in paragraph 328. Criterion 1.3 is ambiguous and likely will not result in any generators being identified unless the Planning Coordinator is violating the TPL standards. Adverse Reliability Impact involves impacts to the system that cause separation, cascading, instability, etc. The TPL standards require the Planning Coordinator to plan to prevent these kinds of events for multiple contingencies. Thus, this criterion should be removed. |
| **Response**: Thank you for your comment. | | |

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| Criterion 1.3 - The burden for identifying Critical Assets is with the Responsible Entity that is the asset owner. If it is determined through system studies that a unit must run in order to preserve the reliability of the BES, such as due to a category C3 contingency as defined in TPL-003 or a category D contingency as defined in TPL-004, then that unit must be classified as a Critical Asset. | | |
| SPS Energy | No | While the changes in the Criteria 1.3 allow generators to be informed of whether they are designated a Critical Asset by the Planning Coordinator or Transmission Planner, that was not the point. The discretion to make such designations without proper due diligence or independent review remains. Planning studies have a wide latitude of assumptions and it would be quite easy designate one's competitor as critical and employ the assumptions in the planning models to make that happen. Lacking independence at the PC and TP level, independent review is the only way to insure competition is not blunted by this ability to designate one's competitor as critical. |
| **Response**: Thank you for your comment.<br><br>Criterion 1.3 - In the Functional Model, one of the tasks of the Planning Coordinator is “Facilitates the integration of the respective plans of the Resource Planners and Transmission Planners within the Planning Coordinator area.<br><br>a. Reviews the integrated plan with respect to established reliability needs considering the impact on and by adjoining systems.<br><br>b. In coordination with the Resource Planners and Transmission Planners, facilitates the development of alternative solutions for plans that do not meet those reliability needs.”<br><br>One of the alternative solutions developed may require the availability of a particular generator to meet reliability needs and avoid an Adverse Reliability Impact<br><br>Likewise, one of the tasks of the Transmission Planning function is “Evaluate, develop, document, and report on expansion plans for the Transmission Planner area. Assess whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements.” | | |

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| Duke Energy | Yes | Yes, however we see much room for improvement and offer the following comments:<br><br>o Criterion 1.2 - We previously commented that 1000 MVAR was too large, and reiterate that comment again. There are not any reactive resources that large in SERC. Is the drafting team aware of where any 1000 MVAR resources are located?<br><br>o Criterion 1.3 - This criterion is less clear than before. Adding the phrase "necessary to avoid BES Adverse Reliability Impacts" potentially broadened this criterion to include every last generator on the system, because the defined term "Adverse Reliability Impact" includes tripping of generation. You need to limit this criterion to generation whose loss "could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages."<br><br>o Criterion 1.4 - Need to clarify that this criterion only includes the primary Blackstart Resources. Entities may include various alternative resources in their restoration plans which aren't Critical Assets, but which may not be clearly distinguished from the primary Blackstart Resources in the restoration plan. Add the phrase "that the entity intends to rely on for system restoration".<br><br>o Criterion 1.7 - Wording change creates confusion as to whether generating stations are included. Insert the word "transmission" before the word "stations".<br><br>o Criterion 1.8 - This criterion is less clear than before. Delete the RC, because the identification of facilities to be protected occurs in the planning timeframe. Also the unclear language "critical to the derivation of" and "their associated contingencies" should be struck. Suggested rewording: "Transmission Facilities at a single transmission station or substation location, that are identified by the Planning Authority or Transmission Planner, whose loss could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages."<br><br>o Criterion 1.9 - This criterion is less clear than before. Delete the RC, because the identification of facilities to be protected occurs in the planning timeframe. Also the unclear language "critical to the derivation of" and "their associated contingencies" should be struck. Suggested rewording: "Flexible AC Transmission Systems (FACTS) at a single transmission station or substation location, that are identified by the Planning Authority or Transmission Planner, whose loss could expose a widespread |

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| | | area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages."<br><br>o Criterion 1.10 - Removing the word "directly" creates significant uncertainty regarding what scope of facilities would be included. Reinsert the word "directly", preferably after the phrase "Transmission Facilities". Also, including the word "destroyed" in the phrase "destroyed, degraded, misused or otherwise rendered unavailable" creates significant uncertainty regarding what is intended. Add the phrase "via cyber attack" after the word "unavailable". This will clarify that the evaluation only encompasses destruction, degradation or misuse that can be achieved via cyber attack, and not a physical attack on the facilities.<br><br>o Criterion 1.12 - The added language is unclear. Suggested rewording: "Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system that operates BES Elements whose loss could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages for failure to operate as designed."<br><br>o Criterion 1.13 - As clarified on the Webinar, the language needs to be revised to clarify that the phrase "Each system or Facility" only includes discrete systems or facilities that can individually shed 300 MW or more of load. UFLS and UVLS systems are typically composed of discrete components at many locations (not interconnected), usually on the distribution system. These discrete, localized facilities would not typically interrupt 300 MW individually.<br><br>o While the Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities provides milestones for implementing the CIP standards, we believe that a modification is needed related to the CIP 002 milestones within this plan. The implementation plan presumes that compilation of all of CIP 002 evidence (R1. Application of Methodology; R2. Identification of the new Critical Asset; R3. Identification of the new Critical Cyber Assets; and R4. Annual Approval of the above items) occurs simultaneously for Category 1 and Category 2. This approach does not allow sufficient time for the identification of new Critical Cyber Assets (R3) and approval of the documented CCA list (R4) once new Critical Assets are identified. We believe the Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities should be amended to provide a period of 6 months following identification of a new Critical Asset for the |

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| | | identification of new Critical Cyber Assts associated with the new Critical Asset (R3) and the Annual Approval of the revised Critical Cyber Asset List (R4). |

**Response**: Thank you for your comments.

Criterion 1.2 - The value of 1000 MVAR used in this criterion is a value deemed reasonable for the purpose of determining criticality. The survey that NERC conducted earlier this year showed that there were facilities that would qualify at this threshold.

Criterion 1.3 – Adverse Reliability Impact is defined as "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." The Guidance document has been modified to provide additional clarification on this issue.

Criterion 1.4 - The SDT considered using the word "primary", but ultimately rejected it as it is not a defined NERC Glossary term in this instance, nor is it used in EOP-005-2. The phrase "that the entity intends to rely on for system restoration" was discussed by the SDT, but it was determined that it added no additional clarity.

Criterion 1.7 - The choice of the phrases "Transmission Facilities" and "transmission stations or substations" was intentional to exclude connections to generators and generation only substations.

Criterion 1.8 - According to FAC-014-2 Requirement R1 "The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology." Since they have a responsibility to ensure that the IROLs are established and consistent with their SOL methodology, it is valid to list them in this Criterion. The wording for criterion 1.8 came from FAC-014-2 Requirement R5.

Criterion 1.9 - According to FAC-014-2 Requirement R1 "The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology." Since they have a responsibility to ensure that the IROLs are established and consistent with their SOL methodology, it is valid to list them in this Criterion. The wording for criterion 1.8 came from FAC-014-2 Requirement R5.

Criterion 1.10 - Several commenters in the first posting were concerned about the use of the term "directly." After consideration by the Standard Drafting Team, it was determined that the term could be removed without affecting the intent of the criterion. The SDT discussed your suggested

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| changes, and determined the existing language is adequate. The term “destroyed” is listed in the definition of Critical Asset.<br><br>Criterion 1.12 - The SDT appreciates the suggestion, but believes the posted wording is adequate.<br><br>Criterion 1.13 - The SDT spent considerable time discussing the wording of criterion 1.13, and chose the term “Each” to represent that the criterion applied to a discrete system or Facility.<br><br>Implementation Plan – Thank you for raising this concern. The SDT will review the implementation plan in the next version and revise as necessary. | | |