Consideration of Comments

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 - Draft 1
Comment Period Start Date:	2/28/2023
Comment Period End Date:	4/13/2023
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 EOP-011-4 IN 1 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 Implementation Plan IN 1 OT 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Phase 2 TOP-002-5 IN 1 ST

There were 64 sets of responses, including comments from approximately 152 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director, Standards Development Latrice Harkness (via email) or at (404) 858-8088.

Questions

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

1. Proposed EOP-011-4 Requirement R2 was drafted to address recommendation 1h. Do the changes in EOP-011-4 Requirement R2 provide sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response?

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2. The standard drafting team (SDT) made changes to the applicability section based on the recommendation above (additional clarity included in the technical rationale). Do you believe these are the correct Functional Entities to include? If not, please provide details and any other Functional Entities be added with justification.

3. Is the implementation timeframe for EOP-011-4 Requirement R7 reasonable given that it is applicable to Functional Entities who were not previously included in Applicability for EOP-011-3?

4. Do the changes in EOP-011 provide sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding?

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5. Please comment on whether information pertaining to the generating unit’s MWs, including MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather, would be useful to your operations during local forecasted cold

weather. Alternatively, is there a better way for the BA to develop assumptions related to cold weather needs to address this specific metric rather than asking for this information from the GO/GOPs? Please provide comments and revisions to the draft language.

6. Recommendation 1g, bullets 2 and 3 of the Report suggests that each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator to determine total generating capacity that can be relied upon during “local forecasted cold weather,” and utilize such information to “prepare its analysis functions and Real-time monitoring,” and to “manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns” as part of its Capacity and Energy Emergency Operating Plans.” The SDT proposes a new Requirement R8 in TOP-002 that requires a Balancing Authority to create an extreme cold weather Operating Process within its Operating Plan to formalize the Balancing Authority’s analysis functions and Real-time monitoring of its Balancing Authority Area during extreme cold weather. Do you agree the language in proposed Requirement R8 of TOP-002 addresses the intent of and is the appropriate manner in which to satisfy Recommendation 1g? Please provide the reasoning or justification for your position in the comments.

7. The SDT proposes that the modifications in EOP-011-4, EOP-012-2, and TOP-002-5 meet the key recommendations in The Report in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

8. Do you agree with the implementation plan proposed by the SDT? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

9. Is there any part of the proposed requirements, as currently drafted, that is unclear? If so, how would you make it clearer?

10. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC

					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Ryan Strom	Buckeye Power, Inc.	5	RF
					Dave Hartman	Arizona Electric Power Cooperative	1	WECC
					Scott Brame	NC Electric Membership Corporation	3,4,5	SERC
					Jordan Mcclellan	Southern Illinois Power Cooperative	1	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO

					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO

					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF

					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC

					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC

					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Sean Cavote	PSEG	4	NPCC

					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
Tim Kelley	Tim Kelley		WECC	SMUD	Ryder Couch	Sacramento Municipal Utility District	5	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC

					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC

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1. Proposed EOP-011-4 Requirement R2 was drafted to address recommendation 1h. Do the changes in EOP-011-4 Requirement R2 provide sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response?

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

The changes proposed do not speak to or provide sufficient clarity to how TOPs will acquire the information necessary to properly identify and prioritize those critical gas infrastructure facilities such that their sources of electrical power can be determined – thereby allowing them to be properly considered within any automatic or manual load shedding program. There needs to be provisions indicating that the entities that are the owners and operators of critical natural gas infrastructure facilities will provide lists and addresses of those facilities such that TOPs can properly identify them and their source of electrical power. Without requirements for the gas infrastructure entities to supply and maintain a list of these facilities to the TOPs, we would not be in a position to reliably identify them nor prioritize them.

Likes 1	Platte River Power Authority, 1, Archie Marissa
Dislikes 0	

Response

Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the recurring label of "critical natural gas infrastructure" is vague and undefined. Will there be a term created and placed in the NERC Glossary? Further, what specifically designates any one particular natural gas infrastructure as “critical” versus another as “non-critical”? Are electrical transmission / distribution entities being asked to designate natural gas infrastructure as critical or non-critical? BPA, as large Transmission entity, does not possess the information to make those determinations. BPA seeks clarity pertaining to what, if any, authorities are in place (or expected to be put in place) for BA, TO, TOP, DP, or UFLS-only DP to request/demand natural gas companies provide Critical Information about their facilities? BPA views this as potential overreach to require entities to do something BPA, as a Transmission entity, lacks the information or authority to do.	
Likes 2	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	No
Document Name	
Comment	
The changes do not identify how or who will be responsible for determining and identifying the critical natural gas infrastructure.	
Likes 1	Platte River Power Authority, 1, Archie Marissa
Dislikes 0	
Response	
Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
RF has concerns regarding consistent identification of critical natural gas infrastructure. The Technical Rationale document states "the identification of critical natural gas loads can be accomplished in several ways and the SDT did not prescribe specific methods in the drafting of EOP-011-4" but does goes on to provide some examples of methods. However, the current draft appears to leave open the possibility that the BA, TOP, TO, and DP/DP-UFLS may disagree on whether any given load is a "designated critical natural gas infrastructure load."	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. Additional content has been added to the Technical Rationale to address these topics.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No

Document Name	
Comment	

MRO NSRF requests that the term "critical natural gas infrastructure load" be defined. Additionally, MRO NSRF would request that the definition, at a minimum, state "critical natural gas infrastructure load" is natural gas infrastructure load that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System. The definition of BES Cyber Asset (included below) can be looked to for language similar to what MRO NSRF is requesting.

BES Cyber Asset

A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.

Recommendation 1i states: To protect critical natural gas infrastructure loads from manual and automatic load shedding (to avoid adversely affecting Bulk Electric System reliability):

- **To require Balancing Authorities' and Transmission Operators' (TOPs) provisions for operator controlled manual load shedding to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas;**
- **To require Balancing Authorities', Transmission Operators', Planning Coordinators', and Transmission Planners' respective provisions and programs for manual and automatic (e.g., underfrequency load shedding, undervoltage load shedding) load shedding to protect identified critical natural gas infrastructure loads from manual and automatic load shedding by manual and automatic load shed entities within their footprints;**
- **To require manual and automatic load shed entities to distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads; and**
- **To require manual and automatic load shed entities to incorporate the identified critical natural gas infrastructure loads into their plans and procedures for protection against manual and automatic load shedding.**

Likes 2	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad; and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments below:

The text of Requirement R2.2.8 requires the Balancing Authority to include provisions in their Operating Plan(s); however, the published Technical Rationale document does not align with the Requirement text.

Excerpt from published Technical Rationale (emphasis added):

“EOP-011-4 Requirement 2.2.8 was added to require Balancing Authorities to include provisions to identify and prioritize critical natural gas loads in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5 applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of critical natural gas Loads applicable to Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8.”

Which is it? Is the Balancing Authority required to identify and prioritize or merely to include provisions in their Operating Plan(s) to exclude critical natural gas infrastructure loads?

While it is recognized that coordination of load shedding schemes may be (and likely will be) necessary at the Balancing Authority level, it should not be incumbent upon the Balancing Authority to identify critical natural gas infrastructure loads. Critical loads should be identified at a single operating level to prevent duplication and/or conflicting identifications. It is our recommendation that this identification of critical natural gas infrastructure loads should occur at the TOP level. Thus, we recommend modifying the text of this requirement as follows: "2.2.9. Provisions for excluding critical natural gas infrastructure loads, as identified by the TOP, from load shedding schemes (i.e., Interruptible Load, curtailable Load, or demand response) during periods when it would adversely impact the reliable operation of the BES;	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Technical Rationale has been modified to more appropriately address the language in R2.2.8 and R2.2.9.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
Where generation is continuing their efforts to increase their layers of freeze protection measures, enough is *not* being done to minimize the risk and improve reliability with the emphasis on fuel. Not just natural gas but a complete diversity to ensure the US power grid has all necessary fuels for generation in any extreme condition. While electric demand is increasing, reliable generation resources are decreasing. The focus for renewables need to continue, but a review of current trends need to be weighed against the reliability and the increasing demands for today and the future. IPPs are forced to make business decisions based on market/tariff agreements during volatile conditions that can and does impact the livelihood for generation facilities. During extreme weather conditions reliability should become the priority and the market aspects or penalties should be removed from the equation. The RC, BA, TOP should be working together with congress to ensure the fuels are available and the grid is diverse enough for its reliable operation.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	

WECC believes the use of the term “critical” is ambiguous and formally undefined. Requirement 2 as written specifies the BA must exclude critical natural gas infrastructure loads from consideration as interruptible load, curtailable Load and demand response. Requirement 1 allows (requires) the TOP to identify the critical natural gas infrastruction loads. The FERC recommendation contained a description of “critical natural gas infrastructure loads” as “natural gas production, processing and intrastate and interstate pipeline facility loads which, if deenergized, could adversely affect provision of natural gas to bulk-power system natural gas-fired generation.” If this description is to be used by the TOP’s when identifying the critical natural gas infrastructucture loads WECC feels it should be added to the NERC Glossary of Terms or stated explicitly in the standard.

Also WECC believes it is not clear if the description provided would only apply to BES Generation Facilities that are defined as applicable in Section 4.2.1 of EOP-012-1 or considered for any BES Generation as the description implies.

The technical rational describes the consideration of “critical” gas infrastructure to be considered on a priority scale with some “critical” loads being a higher priority than other “critical” loads. WECC believes this aglso makes the use of the term “critical” ambiguous.

It was noted that EOP-011-4 does not contain any requirement for the TOP to provide the list of identified critical natural gas infrastructure loads to the Balancing Authority that must consider them in Requirement 2. This could be addressed by modification of the BA Data Specifications of TOP-003-4. But since this would be relatively unchanging information it might be preferable to specify its distribution in EOP-011-4.

WECC recommends the standard include more specific direction for identification of critical natural gas infrastructure loads for the TOP and to require communication of this information to all BA's which share its footprint. Alternately in line with the variable priorities discussed in the technical rational consider deleting the term "critical" and simply addressing the prioritization of natural gas infrastructure providing service to BES generation.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The SDT discussed and declined to create a separate provision that would require Transmission Operators to provide a listing of critical natural gas infrastructure loads to the Balancing Authority. If necessary, this could be obtained by the Balancing Authority though their Data Specifications.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	
In addition to PJM supporting the IRC SRC comments, PJM requests striking the language: 'during periods when it would adversely impact the reliable operation of the BES;' from R2.2.8. This is due to balancing Load and generation during emergency conditions and the concern with any possible interruption of natural gas fired resources. There is also a potential to impact other Balancing Authority Areas since critical natural gas infrastructure would most likely extend beyond the host Balancing Authority's footprint.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT determined that a complete prohibition is not necessary at all times given that the natural gas system does not have the same limitations and criticality during all seasons and weather conditions. The SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

For the purpose of this standard, WEC Energy Group suggests stating that "critical natural gas infrastructure load" is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
The addition of R2.2.8 seems repetitive since the BA is required in R2.2.9 (previously R2.2.8) to have provisions to implement manual load shed in accordance with R1.2.5 which already states the requirement to minimize the overlap of critical loads in manual load shed circuits. The SDT should consider adding "or automatic" to R2.2.9 to correspond to the language of "or automatic" being added to R1.2.5. Additionally R1.2.5 could be read to include Operator Controlled Automatic Load-shed. The SDT should consider modifying R1.2.5 as follows to clearly identify both in the sub-requirement: R1.2.5. Operator Controlled manual load shedding and automatic load shedding during an Emergency that accounts for each of the following: Recommended change: 2.2.9 Provisions for Transmission Operators to implement operator-controlled manual or automatic Load shed in accordance with Requirement R1 Part 1.2.5; and	

If the requirement remains, ISO-NE would support an addition to the NERC Glossary of Terms for "Critical Natural Gas Infrastructure"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has incorporated these suggestions into the latest draft.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
WAPA requests that the term "critical natural gas infrastructure" be defined. Additionally, WAPA would request that the definition, at a minimum, state "critical natural gas infrastructure" is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

We would like the SDT to clarify if the critical natural gas infrastructure loads to be identified are only in reference to electric generation or if it relates to all natural gas delivery. We believe the term "critical natural gas infrastructure loads" should be further explained / bounded within the standard, perhaps in a footnote(s). The technical rationale document for EOP-011-4 states that "the SDT did not prescribe specific methods [for identifying critical natural gas infrastructure loads] in the drafting of EOP-011-4", and notes three possible methods. The rationale document also suggests that a prioritization criteria be developed for critical natural gas infrastructure loads under various conditions. Recommendation 1i suggests that manual and automatic load shed entities distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads. As written, R1 (part 1.2.5.5) and R2 (Part 2.2.8) could result in a wide range of interpretations.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.

Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	

Comment
Minnesota Power supports MRO's NERC Standards Review Form (NSRF) comments.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	2021-07_Cold_Weather_Phase 2_Unofficial_Comment_Form_SRC_04-12-23 - Clean.docx
Comment	

As written, Requirement R2 does not provide sufficient clarity. To provide adequate clarity, the ISO/RTO Council (IRC) **Standards Review Committee (SRC)[1] recommends the term "critical natural gas infrastructure load" be defined**. The definition should be:

· **Flexible** – to recognize that some Responsible Entities may already be subject to an approved definition for their jurisdiction (*see* proposed language below):

o ***Critical Natural Gas Infrastructure Load*** *- Shall have the meaning established by the Responsible Entity's approved governing documents or by the applicable regulatory authorities, or, if no applicable definition exists, is defined as electric loads that are involved in natural gas production, processing, or transmission or distribution, both intrastate and interstate, which if curtailed will impact the delivery of natural gas to bulk-power system natural gas-fired generation.*

· **Results-based and premised on reliability** - to minimize adverse impacts to the reliable operation of the Bulk Electric System. Portions of the definition for *BES Cyber Asset* may serve as a useful reference for appropriate language.

o ***BES Cyber Asset*** *- A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems*.

Finally, the **SRC requests the standard acknowledge that the ability to identify critical natural gas infrastructure loads requires the cooperation of natural gas providers, which are outside of NERC's jurisdiction, and other Registered Entities, such as DPs**. The ability of Responsible Entities to comply with the Standard should not depend on the extent to which natural gas providers are willing to work with Responsible Entities to identify critical natural gas infrastructure loads. Additionally, the obligations of Responsible Entities should be limited

to *known* critical natural gas infrastructure loads. Consequently, the SRC recommends that Requirement 2.2.8 be limited to known critical natural gas infrastructure loads, as follows: “Provisions for excluding *known* critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES;” [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
The text of Requirement R2.2.8 requires the Balancing Authority to include provisions in their Operating Plan(s); however, the published Technical Rationale document does not align with the Requirement text.	

Excerpt from published Technical Rationale (emphasis added): "EOP-011-4 Requirement 2.2.8 was added to require Balancing Authorities to include provisions to identify and prioritize critical natural gas loads in their Operating Plan(s), similar to EOP-011-4 Requirements R1.2.5 and R7.1.5 applicable to Transmission Operators, Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. The Technical Rationale verbiage above regarding the identification and prioritization of critical natural gas Loads applicable to Requirements R1.2.5 and R7.1.5 is also applicable to Requirement R2.2.8." Which is it? Is the Balancing Authority required to identify and prioritize or merely to include provisions in their Operating Plan(s) to exclude critical natural gas infrastructure loads? While it is recognized that coordination of load shedding schemes may be (and likely will be) necessary at the Balancing Authority level, it should not be incumbent upon the Balancing Authority to identify critical natural gas infrastructure loads. Critical loads should be identified at a single operating level to prevent duplication and/or conflicting identifications. It is our recommendation that this identification of critical natural gas infrastructure loads should occur at the TOP level. Thus, we recommend modifying the text of this requirement as follows: "2.2.9. Provisions for excluding critical natural gas infrastructure loads, as identified by the TOP, from load shedding schemes (i.e., Interruptible Load, curtailable Load, or demand response) during periods when it would adversely impact the reliable operation of the BES;"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Technical Rationale has been modified to more appropriately address the language in R2.2.8 and R2.2.9.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

PacifiCorp requests that the term “critical natural gas infrastructure” be defined. Additionally, PacifiCorp would request that the definition, at a minimum, state “critical natural gas infrastructure” is natural gas infrastructure that if rendered unavailable would adversely impact generator output and would affect the reliable operation of the Bulk Electric System. The definition of BES Cyber Asset (included below) can be looked to for language similar to what PacifiCorp is requesting.

BES Cyber Asset

A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP believes the revisions provide clarity.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CenterPoint Energy Houston Electric, LLC (CEHE) agrees that the proposed EOP-011-4 Requirement R2 language provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon - 3	

Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees that the proposed EOP-011-4 Requirement R2 language provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment

Southern Company agrees with EEI comments that the language in proposed EOP-011-4, Requirement R2, provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response systems. However, Southern Company would point out a potential gap in the standard concerning TO/DP exclusion of Critical Natural Gas Infrastructure loads in their Demand Response Programs.

Language for the use of and provision for excluding Critical Natural Gas Infrastructure loads as demand response to mitigate Energy Emergencies within the Balancing Authority Area is only present in the R2 requirements for BA. R1 requirements for TOP and R7 requirements for TO/DP only require provisions for the identification and prioritization of Critical Natural Gas Infrastructure loads, not the exclusion from Demand Response Programs. As written, the standard gives the BA no authority to require that TOs or DPs develop their Demand Response programs in this manner and the BA Operating Plans(s) can only accommodate what is provided by the TOP, TO, and DP.

To close this gap Southern Company would suggest that parallel requirements to R2.2.8 be placed upon the TOP, TO, and DP to exclude any identified designated critical natural gas infrastructure loads in their Demand Response Program offered for use in the BA Operating Plan(s) to mitigate Energy Emergencies during periods when it would adversely impact the reliable operation of the BES. The Commission should clarify that critical natural gas infrastructure can participate in Demand Response Programs such as real-time pricing which do not restrict the natural gas facilities from operating during energy emergencies.

Recommendation 1i states: To protect critical natural gas infrastructure loads from manual and automatic load shedding (to avoid adversely affecting Bulk Electric System reliability):

• To require Balancing Authorities' and Transmission Operators' (TOPs) provisions for operator controlled manual load shedding to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas;

• To require Balancing Authorities', Transmission Operators', Planning Coordinators', and Transmission Planners' respective provisions and programs for manual and automatic (e.g., underfrequency load shedding, undervoltage load shedding) load shedding to protect identified critical natural gas infrastructure loads from manual and automatic load shedding by manual and automatic load shed entities within their footprints;

• To require manual and automatic load shed entities to distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads; and

• To require manual and automatic load shed entities to incorporate the identified critical natural gas infrastructure loads into their plans and procedures for protection against manual and automatic load shedding.	
Likes 0	
Dislikes 1	Platte River Power Authority, 1, Archie Marissa
Response	
Thank you for the comment. The SDT feels it is appropriate to limit this to the Balancing Authorities Operating Plan(s) as per Key Recommendation 1h.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Comments: *The SDT may want to consider defining the term "Critical Natural Gas Infrastructure Load" while recognizing that some Responsible Entities may already have an approved definition in place for their jurisdiction (see proposed language below):* *Critical Natural Gas Infrastructure Load - Shall have the meaning established by the Responsible Entity's approved governing documents or by the applicable regulatory authorities, or, if no applicable definition exists, is defined as any natural gas infrastructure load, if de-energized, could adversely impact BES reliability".*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	

PNM is in agreement that there is sufficient clarity regarding EOP-011-4 R2 and is in agreemetn with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	

Comment	
Evergy supports and incorporates the comments of the Edison Electric Institue (EEI) to question #1,	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that the language in proposed EOP-011-4, Requirement R2, provides sufficient clarity in regards to limiting critical natural gas infrastructure participation in demand response systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates and supports the standard drafting team's (SDT) efforts in address the Joint Inquiry report for Winter Storm Uri. Texas RE is concerned, however, that Balancing Authorities (BAs), the entities responsible for developing Operating Plans in EOP-011-4 R2 may lack sufficient information to properly design those plans. As an initial matter, Texas RE notes that there is no provision for the BA receiving information regarding critical natural gas infrastructure loads. Texas RE recommends an explicit requirement for the BA to receive the critical natural gas infrastructure load information. Texas RE is also concerned the BAs may not receive information on the criticality of natural gas loads in multiple TOP Areas. If the natural gas infrastructure is in TOP Area 1 but affects units in TOP Area 2, it is unclear how TOP Area 2 would recognize the impact. Moreover, while Texas RE understands the need for flexibility, Texas RE is also concerned the phrase "when it would adversely impact the reliable operation of the BES" does not fully meet the recommendation objective to "prohibit use" of critical natural gas infrastructure loads for demand response. As noted in the February 2021 Cold Weather Outages in Texas and the South Central United States Joint Inquiry Report ("Joint Inquiry"), BA operating plans may include natural gas infrastructure loads in demand response programs. In contrast, however, designated critical natural gas infrastructure loads which, "if de-energized, would adversely affect BES natural gas-fired generation" should be prohibited from participating in demand response programs. (Joint Inquiry, at 207). The proposed EOP-011-4 R2.2.2.8 language appears to permit critical natural gas infrastructure to participate in demand response programs if it would not adversely impact reliability. However, as the Joint Inquiry defines "critical natural gas infrastructure loads" as "natural gas infrastructure loads which, if de-energized, could adversely affect the provision of natural gas to BES-fired natural gas-fired generating units, thereby adversely affecting BES reliability," the inclusion of critical natural gas infrastructure should, by definition, adversely impact BES reliability. Instead of effectively creating a hollow provision and potential confusion, Texas RE recommends either removing this phrase "when in would adversely impact . . . BES" and/or clarify that non-critical natural gas infrastructure loads may be properly included in BA-developed demand response programs. Texas RE recommends the requirement apply to any manual or automatic load shed programs. The term "Interruptible Load" references the inactive function LSE. The other terms, curtailable Load and demand response, are not defined.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT discussed and declined to create a separate provision that would require Transmission Operators to provide a listing of critical natural gas infrastructure loads to the Balancing Authority. If necessary, this could be obtained by the Balancing Authority though their Data Specifications. The SDT discussed whether the exclusion of critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response should be limited to certain situations or be a complete prohibition. The SDT determined that a complete prohibition is not necessary at all times given that the natural gas system does not have the same limitations and criticality during all seasons and weather conditions. The SDT has limited the exclusion of these loads from Interruptible Load, curtailable Load, and demand response only to periods of extreme cold weather. Entities should note that the proposed Standard represents a minimum requirement which can be exceeded by individual entities if deemed appropriate. EOP-011-4 requirements that address manual load shedding or automatic load shedding are primarily in R1 and R8, not R2.2.8.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	

Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A to Hydro One	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

2. The standard drafting team (SDT) made changes to the applicability section based on the recommendation above (additional clarity included in the technical rationale). Do you believe these are the correct Functional Entities to include? If not, please provide details and any other Functional Entities be added with justification.

Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	
The NERC Reliabilty Standard for Undervoltage Load Shedding, PRC-010-2 references “UVLS entities” as an applicable entity. GSOC suggests considering UVLS entities be a Functional entity that would apply under “automatic Load shedding” for R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. PRC-010-2 defines UVLS entities as “Distribution Providers and Transmission Owners responsible for the ownership, operation or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.” Distribution Providers and Transmission Owners have been included in the Applicability section of EOP-011-4 so it is not necessary to also include the term “UVLS entities.”	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	

Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT disagrees. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT disagrees. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We don't believe that the proposed changes to the applicability section sufficiently address recommendation 1i. The recommendation references the roles of the Planning Coordinator and Transmission Planner in regard to automatic load shedding (e.g., underfrequency load shedding, undervoltage load shedding), but those entities have not been addressed. While the entities added (DP, UFLS-Only DP, TO) have a role in implementing automatic load shedding programs developed by the PC or TP, we believe the drafting team should consider changes to the PRC-006 (Automatic Underfrequency Load Shedding) and PRC-010 (Undervoltage Load Shedding) standards to more fully address recommendation 1i. We question the addition of "or automatic" in R1, Part 1.2.5. We suggest the following restructuring for R1, Part 1.2.5: 1.2.5. Operator-controlled manual Load shedding during an Emergency that accounts for each of the following: 1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency; 1.2.5.2. Provisions for identifying any other entities (DP, TO) that help execute manual Load shedding during an Emergency; 1.2.5.3. Provisions for the periodic identification and prioritization of designated critical loads, including critical natural gas infrastructure loads;	

1.2.5.4. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads, including critical natural gas infrastructure loads; 1.2.5.5. Provisions for periodic coordination with the appropriate UFLS Entities and UVLS Entities to obtain information on their circuits that are utilized for automatic underfrequency load shed (UFLS) or automatic undervoltage load shed (UVLS); and 1.2.5.6. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for automatic underfrequency load shed (UFLS) or automatic undervoltage load shed (UVLS).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed the inclusion of the Planning Coordinator and Transmission Planner roles in Key Recommendation 1i and determined that it was not necessary to include them in EOP-011-4. The SDT also determined that it was not necessary to make changes to PRC-006 or PRC-010. The reasoning for this is that the Planning Coordinator and Transmission Planner responsibilities in PRC-006 and PRC-010 are primarily around the development UFLS programs and UVLS programs. The implementation of those programs is handled by UFLS entities and UVLS entities which by definition includes Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. EOP-011-4 does not address the development of UFLS Programs and UVLS Programs. Changes were made to R1.2.5, R2.2.9 and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports TPWR comments.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT disagrees. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No

Document Name	
Comment	
Tacoma Power requests additional clarity on the applicability section. For EOP-011-4 Requirements 1.2.5.5 and 1.2.5.6, does the SDT intend for TOPs to account for all distribution providers in their Operating Plans (even non-BES providers), or is it limited to registered Distribution Providers only? Additionally, is the TOP responsible for identifying critical natural gas infrastructure loads that are located on non-registered distribution provider networks? If this Standard is requiring TOPs to account for non-registered distribution providers, then there may be difficulty collecting this information, since these providers aren't subject to NERC jurisdiction.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The Applicability section and TOP obligations for identifying and notifying in Requirement R7 is limited to entities registered with NERC as a Distribution Provider, UFLS-Only Distribution Provider, or Transmission Owner.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Should not include the additional functional entities as proposed in 4.1.4, 4.1.5 and 4.1.6. This is adding extra layers of coordination and processes that will be complex and difficult due to multiple DPs trying to coordinate in multiple TOs area .. This would be burdensome on the TOP as well.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT disagrees. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Regardless of DP, TO or UFLS-Only DP applicability, BPA believes those entities do not have the legal authority to require natural gas companies to identify and disclose information pertaining to their critical natural gas facilities (locations, etc.). Natural gas entities are not NERC Registered entities. BPA seeks clarity on how this information could be obtained if a natural gas entity refuses to provide its information.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Thomas Foltz - AEP - 5	
Answer	No

Document Name	
Comment	
While AEP does not object to the three entities which have been added as Functional Entities in 4.1.4 through 4.1.6, we believe natural gas owners and operators would need to be added as well. Please see our response to Question 4 regarding their omission.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Natural gas owners and operators are not NERC functional entities and it is outside the scope of the SDT to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question. Additionally, ERCOT would like to highlight that assigning real-time operational tasks to TOs would require modifications to COM, IRO, and TOP Reliability Standards to ensure these entities have the communications infrastructure and compliance responsibilities necessary to reliably receive and execute real-time operating instructions. ERCOT continues to encourage the use of proper registration, Coordinated Functional Registration agreements, or Regional Standards to address scenarios in which one functional entity might be better suited to perform tasks typically carried out by a different functional entity. ERCOT discourages the creation of ambiguous obligations for a functional entity, such as a TO, to perform tasks typically reserved for a different functional entity, such as a TOP or a DP.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with your comment and has made changes in R7 and R8 to more appropriately characterize the roles of Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners as “assisting with the mitigation of operating Emergencies.” In alignment with this change, the term “Operating Plan” in R8 has been changed to “Load shedding plan.”	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

The SRC[1] thanks the SDT for adopting its recommendation made during Project 2021-07 Phase 1 (Draft #1). SRC agrees with the proposed additions to the applicability section, as these functional entities (i.e., Distribution Provider, UFLS-only Distribution Provider and Transmission Owners) have important roles to play in protecting critical natural gas infrastructure loads from load shed.

That said, the SRC is concerned with the use of the proposed language, “Operating Plan,” in the Applicability section and in Requirement R7, as it may be construed to assign UFLS-Only Distribution Providers and Transmission Owners real-time operational tasks that they are not equipped to handle. Therefore, SRC recommends the language “to mitigate operating Emergencies” in applicability sections 4.1.5 and 4.1.6 be revised to read “to assist with mitigating operating Emergencies,” and that the language in R7 be modified as indicated below. Other clarifications to Requirement R7 are also proposed in the SRC’s response to Question 9.

R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator’s Operating Plan(s) to *assist with* mitigat*ing* operating Emergencies in its Transmission Operator Area shall, *in consultation with the Transmission Operator, develop, maintain, implement, and provide to the Transmission Operator an Operator-controlled manual, or automatic Load shedding program, that accounts for each of the following, as applicable:* [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with your comment and has made changes in R7 and R8 to more appropriately characterize the roles of Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners as “assisting with the mitigation of operating Emergencies.” In alignment with this change, the term “Operating Plan” in R8 has been changed to “Load shedding plan.”	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Recommend specifically identifying that the Operating Plans that make a TO/DP/DP-UFLS applicable are those referenced in R1. Curently written, this could be interpereted as any TO/DP/DP-UFLS that is part of a TOP Operating Plan to mitigate operating Emergencies is applicable to EOP-011-4. See applicability section of PRC-023 as an example.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the approach of identifying and notifying Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to make this clearer in R7 and R8.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	

Comment	
This seems to be the correct entities to include in the applicability section The SDT should consider adding automatic to EOP-011 R7.1.2. As in R1.2.5.2, the sub-requirements only call for the minimization of overlap between MANUAL load shed circuits and designated critical loads. Adding automatic to R7.1.2 would emphasize the minimization of overlap for both manual and automatic load shed circuits, while not prohibiting the overlap where it may be necessary as stated in the technical rationale. Although the intent is there, the standard doesn't explicitly address that potential overlap. Recommend adding automatic to R7.1.2 The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does this make sense to specifically call it out in a separate requirement. The SDT should consider whether or not to include a new term in the NERC Glossary of "Designated Critical Load" which would define what the minimum standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear feeds, public safety, public health, etc. A recommendation for language is provided in ISO-NE's response to Question 4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Changes were made to R1.2.5, R2.2.9, and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding. The SDT discussed and chose to maintain the separate provisions related to the identification and prioritization of critical natural gas infrastructure in 1.2.5.5 and 8.1.5.	

The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment, please see response to MRO NSRF.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees that TOs, DPs and UFLS-Only DPs are the correct Functional Entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM is in agreement that with the three additions to the functional entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
There is a concern with the use of the proposed language, “Operating Plan,” in Requirement R7 as it may denote real-time operational tasks to UFLS-Only Distribution Providers and Transmission Owners that they are not equipped to handle. IESO recommends that “Operating Plan” be replaced with “Load Shedding Procedures”.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT agrees with your comment and has made changes in R7 and R8 to more appropriately characterize the roles of Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners as "assisting with the mitigation of operating Emergencies." In alignment with this change, the term "Operating Plan" in R8 has been changed to "Load shedding plan."	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lindsey Mannion - ReliabilityFirst - 10	

Answer	Yes
Document Name	
Comment	
TO, DP, and DP-UFLS appear to be the correct Functional Entities, but RF recommends considering a requirement for the TOP to notify identified TO, DP, or DP-UFLS Functional Entities. This could be accomplished by revising R1 Part 1.2.5.6 to state “Provisions for the identification and notification of…” or by adding a separate requirement analogous to EOP-005-3 R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees this is an issue and has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Some clarification may be beneficial in regards to whether this is the expectation for natural gas transmission and distribution facilities, or does this expectation also include natural gas production facilities (wells, processing plants, etc).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to	

apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company believes that the language as written is overly broad as to the applicability of DPs. Therefore, Southern Company would suggest language changes in the Applicability section 4.1.4 to include only DPs with identified Critical Natural Gas Infrastructure loads as Applicable Functional Entities:

"4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area **as serving one or more Critical Natural Gas Infrastructure loads** "

Southern Company would also add the following language to clarify R7 to specify that the operating plans now required by the TOs and DPs are to achieve the goal of implementing portions of the TOPs requirements in R1.2.5 as stated in the EOP-011-4 Technical Rationale:

"Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) **as implementing portions of its Requirements in R1.2.5** to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain and implement one or more Operating Plan(s). The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:"

Alternately, R7 could be narrowed such that the DP does not need to develop and Operating Plan so long as the DP communicates to the TOP how the load is served and that no Critical Natural Gas Infrastructure loads are part of any load shed or Demand Response programs. Suggested modifications to R7 are as follows:

"Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) **which serves one or more Critical Natural Gas Infrastructure loads shall communicate to the Transmission Operator how the load(s) is served and verify that the load(s) is not included in the Distribution Provider's manual or automatic load shed programs and that the load(s) is not in a Demand Response Program which would restrict operation during an Energy Emergency.**"

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT disagrees that the Applicability is overly broad and should in fact be applicable beyond just the handling of critical natural gas infrastructure loads. In many cases, Transmission Operators are dependent on Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners to implement portions of Requirement R1.2.5. The SDT determined that is necessary to expand the Applicability of EOP-011-4 to these Functional Entities in order to address all entities responsible for performing operator-controlled manual Load shedding or automatic Load shedding per Key Recommendation 1i. To the extent additional coordination is required, this is an appropriate burden to ensure operator-controlled manual Load shedding or automatic Load shedding are performed in a manner that support the reliable operation of the BES.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees that the TOs, DPs and UFLS-Only DPs are the correct Functional Entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	

Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CEHE agrees that the TOs, DPs, and UFLS-Only DPs are the correct Functional Entities.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC agrees with the changes made by the SDT to the applicable entities as these are the entities that have the information the TOP or BA needs to develop appropriate plans. In addition, these are typically the entities with the direct relationships with the end-use customer natural gas infrastructure loads. It is also important to note that successfully complying with the standard requires cooperation from these end-use customers, who have no regulatory obligation to provide this information.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	

Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE agrees with the changes to the applicability section of EOP-011-4. Texas RE recommends that TP/PC also be included so planners will be made aware of critical natural gas infrastructure loads during planning analyses and understand which loads to drop in order to plan effectively (and not exacerbate an operational issue).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed the inclusion of the Planning Coordinator and Transmission Planner roles in Key Recommendation 1i and determined that it was not necessary to include them in EOP-011-4. The SDT also determined that it was not necessary to make changes to PRC-006 or PRC-010. The reasoning for this is that the Planning Coordinator and Transmission Planner responsibilities in PRC-006 and PRC-010 are primarily around the development UFLS programs and UVLS programs. The implementation of those programs is handled by UFLS entities and UVLS entities which by definition includes Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners. EOP-011-4 does not address the development of UFLS Programs and UVLS Programs.	

3. Is the implementation timeframe for EOP-011-4 Requirement R7 reasonable given that it is applicable to Functional Entities who were not previously included in Applicability for EOP-011-3?

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

On behalf of the SERC Generator Working Group (GWG)

We believe the intent is that those loads have been identified within 18 months is reasonable. However, if those critical loads need to be removed, that may not be possible, if, for example, a new feeder must be built. Request clarity that the intent is the former, not latter.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No

Document Name	
Comment	
ATC does not agree that the implementation timeframe for EOP-011-4 Requirement 7 is reasonable. TOPs that are not vertically integrated utilities, like ATC, will need to rely on a number of Distribution Providers to provide information related to prioritization of designated critical natural gas infrastructure. As such, 18 months is not enough time to gather all of the information, modify load shed plans, and train system operators on the new plans. An implementation timeframe of 24 to 36 months would be more realistic.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Eighteen months would not be sufficient for the new Functional Entities (4.1.4 through 4.1.6) to become compliant with their EOP-011 obligations. Additional time will be needed to develop accurate lists of critical gas infrastructure and install Distribution SCADA network equipment to allow load shed to take to place as per R7. AEP instead recommends an implementation period of 36 months. To ensure the success of any implementation period used, AEP believes it would be beneficial if the RTOs provided natural gas providers a registration system that Functional Entities could use to comply with R7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE supports EEI Comments which state: EEI could support 18 months to identify critical natural gas infrastructure, however, 18 months is insufficient for TOs, DPs and UFLS Only DPs to either move those loads to other feeders or in many cases to entirely exclude those feeders from their load shedding programs and find	

other suitable offsetting loads in their place. Often this work requires both engineering and field crew support to fully accomplish. The effort will likely require 36 months to fully implement. For this reason, we suggest a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA disagrees with 18 months as a feasible timeframe to implement EOP-011-4. BPA believes these revisions would require identification of all critical natural gas facilities across BPA's very large transmission network footfrint, which spans the entire Pacific Northwest. BPA believes this could potentially require removal and/or installation of new UFLS relays at all substation locations surrounding that natural gas critiacal load. BPA believes the amount of work required to achieve this, including design and construction activities, could take up to 5+ years. BPA recommends a longer, phased in approach, similar to PRC-005 (PSMP) or PRC-002 (Equipment Monitoring).	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
No,CEHE could support the 18 month implementation timeframe; however, CEHE also supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	

Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon – 3	
Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
As drafted, Southern Company agrees with EEI comments that 18 months is insufficient for DPs to document and implement a plan to identify, designate, and prioritize critical natural gas infrastructure loads. If the standard was narrowed as suggested in our comments for	

Question 2, for DPs to verify the exclusion of gas infrastructure loads from their manual and automatic load shed programs, Southern Company believes 18 months may be sufficient time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
This will be a very difficult implementation time frame for the Distribution Provider to meet. Suggest at least a 48month implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12	

additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
RF recommends the implementation plan specify the timeframe allotted for a TO, DP, or DP-UFLS newly identified in a TOP Operating Plan to develop its own Operating Plan following notification by the TOP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
MRO NSRF is supportive of 18 months; MRO NSRF does not want to see the implementation period go beyond 18 months to ensure all impacted entities have updated load shed plans in place in time for the 2025-2026 Winter Season. Additionally, MRO NSRF refers the Standard Drafting team to Recommendation 28 of *The February 2021 Cold Weather Outages in Texas and the South Central United States* report. The MRO NSRF encourages the standard drafting team to consider how the content of this recommendation can be taken into account. Recommendation 28 states that various entities "should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads…" Recommendation 28 also states that "This Recommendation is necessary to support Key Recommendation 1i, regarding the protection of critical natural gas infrastructure loads."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments below:

There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7.

Furthermore, there is no provision in Requirement R7 for how long a newly identified DP, DP-UFLS, or TO has to develop their Operating Plan(s) in the future. In other words, if at some point in the future the TOP revises their Operating Plan(s) to now include a previously unidentified DP, the verbiage in R7 seems to indicate that the DP would be required to develop an Operating Plan on the same day. We recommend modifying the text of Requirement R7 as follows:

"R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement one or more Operating Plan(s) within six (6) calendar months of being notified by the Transmission Operator. The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:"

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM supports EEI's suggested phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No

Document Name	
Comment	
APS agrees with EEI and supports a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes. The 18-month time frame is sufficient to identify natural gas infrastructure. However, it is insufficient for TOs, DPs, and UFLS Only DPs to either move those loads to other feeders or to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. This work often requires both engineering and field crew support to fully accomplish and will likely require 36 months to fully implement.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates the comments of the Edison Electric Institue (EEI) to question #3,	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI could support 18 months to identify critical natural gas infrastructure, however, 18 months is insufficient for TOs, DPs and UFLS Only DPs to either move those loads to other feeders or in many cases to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. Often this work requires both engineering and field crew support to fully accomplish. The effort will likely require 36 months to fully implement. For this reason, we suggest a phased approach that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	

A phased in implementation time would be more reasonable, 25-50-75-100% on an annual basis starting after 12 months as larger Transmission Entities need a longer implementation period. Under R7 7.1.4 it is not clear what is meant by this sub-requirement and what the impact to implementation may be. It is not clear if this is implying some type of dynamic selection of load based on system conditions or something else so clarity on the intent of this would be helpful.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Please refer to the Technical Rationale for EOP-011-3 for additional explanation on the background of 7.1.4 (which is now 8.1.4). This is the same requirement as was included in EOP-011-3 R1.2.5.4.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group does not agree that the implementation timeframe for EOP-011-4 R7 is reasonable. The 18-month implementation timeframe is insufficient to identify all critical natural gas infrastructure and to modify all impacted operator-controlled or manual load shed	

plans. The 18 months would be sufficient for identification, and an additional 18 months would be necessary for development of new and/or the modification of existing load shed plans to ensure that they are adequately avoiding critical natural gas infrastructure while also meeting the reliability needs of the load shed process. It is also important to remember that this process is contingent on cooperation from natural gas customers, who have no regulatory obligation to provide this information. WEC Energy Group also holds that since natural gas customers must self-identify their critical natural gas infrastructure, the language in the standard should take this into account.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Given our concerns with Draft 1, it's difficult to comment on the reasonableness of an 18 month implementation timeframe. Our sense is that a longer implementation period (perhaps 24 to 30 months) would be more reasonable for some entities given the expanded entity applicability and need to develop and implement a process for identifying "critical natural gas infrastructure loads".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

18 months for the identification of applicable circuits is appropriate, however the implementation of adding those circuits to a load shedding program requires an additional 12-18 months (especially for R7.1.5 critical natural gas infrastructure loads)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
Request 36 months	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7. Furthermore, there is no provision in Requirement R7 for how long a newly identified DP, DP-UFLS, or TO has to develop their Operating Plan(s) in the future. In other words, if at some point in the future the TOP revises their Operating Plan(s) to now include a previously unidentified DP, the verbiage in R7 seems to indicate that the DP would be required to develop an Operating Plan on the same day. We recommend modifying the text of Requirement R7 as follows: "R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement one or more Operating Plan(s) within six (6) calendar months of being notified by the Transmission Operator. The Operating Plan(s) shall be provided to the Transmission Operator. The Operating Plan(s) shall include the following, as applicable:"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends a 24-month implementation timeframe to allow for the coordination, budget revisions, staffing changes, and systems upgrades that may be necessary to accomplish the new tasks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment	
PacifiCorp is supportive of 18 months; PacifiCorp does not want to see the implementation period go beyond 18 months to ensure all impacted entities have updated load shed plans in place in time for the 2025-2026 Winter Season. Additionally, PacifiCorp refers the Standard Drafting team to Recommendation 28 of *The February 2021 Cold Weather Outages in Texas and the South Central United States* report. PacifiCorp encourages the standard drafting team to consider how the content of this recommendation can be taken into account. Recommendation 28 states that various entities "should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads…" Recommendation 28 also states that "This Recommendation is necessary to support Key Recommendation 1i, regarding the protection of critical natural gas infrastructure loads."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees that the 18 month implementation timeframe is reasonable.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	

An 18 month implementation timeframe may be appropriate assuming the NERC Standard is approved through FERC on the same general timetable as the Phase 1 Standards, FERC approval approx. Feb 2024, with effective date of October 1, 2025 which would be prior to the 2025 winter period.

However, the SDT should consider that based on the current status of the SDT through Phase 2 with this version of EOP-011 already at the first ballot, a 12 month timeframe might be appropriate so that if FERC were to approve the Standard in 2023, there would be the possibility of the effective date being prior to the 2024 winter period, or at least near the start of the 2024 winter period.

If Phase 2 Standards revisions were to be adopted before October 1, 2023, the effective date would aling with the expected Effective date of the Phase 1 EOP-011 and EOP-012 which could eliminate a potential risk of compliance with multiple versions of the same Standard.

ISO-NE does not support any implementation timeframe that goes beyond the start of the 2025-2026 Winter.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12

additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The SRC[1] supports an implementation timeframe of 18 months to ensure Requirement R7 is effective in time for the 2025-2026 winter season [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5 and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the	

first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
WECC has no comment on the implementation timeline, and leaves it to the entities that have to implement the requirements to provide feedback.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	

Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

4. Do the changes in EOP-011 provide sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding?	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
EOP-011-4, R2.2.8 states "Provisions for excluding critical natural gas infrastructure loads as Interruptible Load, curtailable Load, and demand response during periods when it would adversely impact the reliable operation of the BES". So if it is "critical," which is not a defined term, it must be excluded from any manual /automatic load shed. This seems to remove flexibility. The flexibility will only show up if it is not classified as "critical" which defeats the purpose of this revision.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Scott McGough - Georgia System Operations Corporation - 3	
Answer	No
Document Name	
Comment	

R1: GSOC agrees with the SDT's recommendation to protect critical natural gas infrastructure loads from automatic Load shedding. However, GSOC has concerns introducing automatic Load shedding requirements within EOP-011-4 under requirements R1.2.5 thereby indicating that it would be applicable to the TOP when the TOP is not responsible for automatic Load shedding schemes. Automatic Load shedding design requirements and corresponding applicable entities are addressed in their respective NERC Reliability Standards PRC-006-5 and PRC-010-2 which includes PC, TP, TO, DP, UVLS entities, and UFLS-Only DP. Alternatively, rather than introducing any automatic Load shedding requirements within EOP-011-4, R1.2.5, GSOC recommends revisions to PRC-006 and PRC-010, accordingly, to introduce new design requirements for "identification and prioritization of designtated critical natural gas infrastructure loads". In doing so, the appropriate subject matter experts responsible for these schemes and requirements would become more aware of this issue and address this concern accordingly. As long as R7 still contains requirements for addressing automatic Load shedding by the responsible entities, the TOP can still identify the appropriate entities required to mitigate operating Emergencies in its Transmission Operator Area under R1.2.5.6 without introducing automatic Load shedding within R1.2.5. R7: The Extreme Cold Weather Preparedness Technical Rationale and Justification for EOP-011-4 document indicates "automatic Load shedding" was introduced to align with sub-requirement "*Provisions for the identification and prioritization of designated critical natural gas infrastructure loads*" to be applicable to automatic Load shedding. For clarity, GSOC recommends separating "Operator-controlled manual Load shedding" from "automatic Load shedding" requirements such that R7.1 only addresses "Operator-controlled manual Load shedding". In addition, requirements 7.1.1 through 7.1.5 and a new R7.2 would only address "automatic Load shedding" (thereby requiring the removal "or automatic" from 7.1. The new R7.2 could read as: "*R7.2 Automatic Load shedding during an Emergency that accounts for provisions for the identification and prioritization of designated critical natural gas infrastructure loads.*"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed the option of making modifications to PRC-006 and PRC-010 and determined that it was not necessary and would be most appropriate to keep these load shed requirements in one location. Each of the sub-requirements under 1.2.5 intentionally utilizes the term "provisions." This term, which has been carried forward from EOP-011-2 and EOP-011-3, is intended to mean that it is the responsibility of the Transmission Operator to work with other entities, as necessary, to ensure that their operating Plan is responsive to these requirements.	

To ensure that all Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners are aware of any new responsibilities the SDT has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
Requirement R1.2.5.6 requires the Transmission Operator to include "provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area" and Requirement R7 requires the affected entities to develop, maintain, and implement an Operating Plan; however, there is no requirement for the TOP to notify the affected entities. How then will the entities identified in the TOP's Operating Plan(s) know that Requirement R7 is now applicable to them? Therefore, we recommend including a requirement for the TOP to notify the affected entities. We propose adding Requirement 1.2.5.7 utilizing the following text. "R1.2.5.7. The TOP shall notify the entities identified pursuant to the application of 1.2.5.6 within 30 days of the latest approved revision date or by the effective date of the Operating Plan; whichever is later." Lastly, we recommend that the identification of designated critical natural gas infrastructure loads should be performed at a single operating level, specifically by the TOP. Thus, we recommend the removal of Requirement R7.1.5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees this is an issue and has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.	

The SDT disagrees that the identification and designation of critical natural gas infrastructure loads should be performed at a single level. This is because Transmission Operators are not necessarily aware of the characteristics or topology of individual loads served by Distribution Providers, UFLS-Only Distribution Providers, or Transmission Owners. It would clearly be beneficial for these entities to collaborate with their Transmission Operator in these activities, but this is not included as a requirement.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
As described in SRC's response to Question 1, the SRC believes the proposed language provides flexibility, but not clarity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Question 1.	
Lori Frisk - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We don’t believe the Draft 1 standard provides sufficient clarity in regards to the treatment of critical natural gas infrastructure with respect to operator-controlled manual Load shedding and automatic load shedding. See responses to Questions 1-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Questions 1 and 2.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
WAPA acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to	

apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports TPWR comments. In addtion, on Question 1, it feels like there is a word missing in the 1h recommendation. Also, what is that is being prohibited in the BA's operating plan? Lastly, how is "critical natural gas infrastructure" defined and what does "demand response of critical natural gas infrstructure load" mean? Or how is "demand response" interpreted here?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent is to prohibit the inclusion of critical natural gas infrastructure loads in various demand response programs. Critical natural gas infrastructure loads that are essential to the reliable operation of the BES should not voluntarily participate in programs that may require them to ramp down or disconnect during extreme cold weather which is when they are needed the most.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID recommends that the SDT develop a definition or guidance for what is considered critical natural gas infrastructure loads in either the Technical Rationale or other Implementation Guidance specific to EOP-011. Furthermore, IID recommends registration of natural gas infrastructure owners and operators.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	

The SDT should consider that the current and proposed language of EOP-011 does not require an entity to minimize the overlap between critical gas infrastructure loads or a designated critical load and automatic load shed circuits. Although the intent is there with the addition of "automatic" in R1.2.5, the standard doesn't explicitly address the potential overlap of critical loads on automatic load shed circuits as it does for manual load shed circuits. Recommend adding automatic to R1.2.5.2. to close that loop.

Recommended change:

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual and **automatic** load shed and circuits that serve designated critical loads, **including designated critical gas infrastructure loads**

The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be be removed is the above proposal is used or be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does it make sense to specifically call out one specific critical load and not others in a separate requirement.

The SDT should consider whether or not to include a new term(s) in the NERC Glossary of "Designated Critical Load" and/or "Critical Natural Gas Infrastructure" which would define what the minimum standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear station service, public safety, public health, etc	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Changes were made to R1.2.5, R2.2.9 and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding. The SDT discussed and chose to maintain the separate provisions related to the identification and prioritization of critical natural gas infrastructure in 1.2.5.5 and 8.1.5. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
The proposed changes in EOP-011 do not provide sufficient clarity. Tacoma Power understands that the SDT does not want to limit or prescribe a single identification method to entities. However, not providing any examples in the Technical Rationale results in lack of clarity, and leaves the definition for the critical natural gas infrastructure loads to each entity. The application of this definition will be inconsistent between entities and auditors. For example, some entities may miss identifying a critical load simply because the entity has a different	

threshold or definition of what is considered “critical.” Tacoma Power recommends that the SDT develop a definition or guidance for what is considered critical natural gas infrastructure loads in either the Technical Rationale or other Implementation Guidance specific to EOP-011.

Tacoma Power recognizes that the Reliability Guideline, “Natural Gas and Electrical Operational Coordination Considerations,” includes guidance on identification of critical natural gas system components and dual-fuel supplier components that could assist with R1.2.5.5. However, Tacoma Power is concerned about the application of this guideline in the absence of a clear definition of what is considered a critical natural gas infrastructure load. Below is a summary of how application of this guideline and lack of a definition can result in confusion or inconsistency.

The Requirement R1.2.5.5 is not clear if critical natural gas infrastructure is focused solely on electric generation load, or if as specified in Chapter 2 of the Reliability Guideline, that non-electric generation load is also considered a “critical” natural gas load. For example, would a natural gas meter at a hospital be considered “critical”? Or is the scope of R1.2.5.5 limited only to major or bulk transmission of natural gas and pipelines that supply natural gas power plants?

Additionally, R1.2.5.5 and the Reliability Guideline is not clear on the responsibilities of a BA or TOP that does not have natural gas generation in their footprint or service territory. For example, if a TOP has a substation that powers a natural gas pipeline which eventually serves a natural gas power plant physically located in the TOP footprint, but the plant is not connected to the TOP’s/TO’s system nor is the plant within their BA’s BAA. This situation exists within Tacoma Power’s footprint and as written, the compliance obligations for meeting R1.2.5.5 are not clear.

Lastly, the Reliability Guideline proposes that electric transmission and distribution owners reach out to regulatory entities, natural gas companies and organizations, and secondary fuel suppliers. Reaching out to this many organizations and agencies, as well as receiving their responses, may be unattainable in the proposed implementation timeline and will be difficult to maintain the coordination. As capured by the MRO NSRF comments, these organizations are not subject to NERC Standards and as a result, may not respond or prioritize coordination with TOPs. Tacoma Power recommends utilizing a note similar to CIP-013 R2 to address this concern. This note should specify compliance with R1.2.5.5 does not include the natural gas companies’ or fuel suppliers’ performance and adherence to the TOP requests.

Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	

Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure load" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates the comments of the Edison Electric Institue (EEI) to question #4,	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

APS believes that clarification is needed because responsible entities do not have the visibility to identify such loads, so they are reliant on natural gas facilities owners, however, natural gas facility owners have no regulatory obligation to self-identify their facilities as critical. To address this concern, APS suggests modifications to Requirement 1, subpart 1.2.5.5 and Requirement R7, subpart 7.1.5 as follows:

Requirement 1, subpart 1.2.5.5:

Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**; and

Requirement R7, subpart 7.1.5:

Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	No
Document Name	

Comment

Please refer back to WECC's comments on question 1. WECC believes the is enough flexibility, but not enough clarity.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Question 1.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	No
Document Name	
Comment	
The changes in EOP-011 do not provide sufficient clarity because the term "critical natural gas infrastructure" is not defined. The SDT should create this definition so that it is clear to entities how to identify these types of loads.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments below:

Requirement R1.2.5.6 requires the Transmission Operator to include “provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area” and Requirement R7 requires the affected entities to develop, maintain, and implement an Operating Plan; however, there is no requirement for the TOP to notify the affected entities. How then will the entities identified in the TOP’s Operating Plan(s) know that Requirement R7 is now applicable to them? Therefore, we recommend including a requirement for the TOP to notify the affected entities. We propose adding Requirement 1.2.5.7 utilizing the following text.

“R1.2.5.7. The TOP shall notify the entities identified pursuant to the application of 1.2.5.6 within 30 days of the latest approved revision date or by the effective date of the Operating Plan; whichever is later.

Lastly, we recommend that the identification of designated critical natural gas infrastructure loads should be performed at a single operating level, specifically by the TOP. Thus, we recommend the removal of Requirement R7.1.5.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees this is an issue and has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.

The SDT disagrees that the identification and designation of critical natural gas infrastructure loads should be performed at a single level. This is because Transmission Operators are not necessarily aware of the characteristics or topology of individual loads served by Distribution Providers, UFLS-Only Distribution Providers, or Transmission Owners. It would clearly be beneficial for these entities to collaborate with their Transmission Operator in these activities, but this is not included as a requirement.

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment	
MRO NSRF acknowledges that the proposed language offers sufficient flexibility; however, it lacks clarity. As highlighted in our response to Question #1, we request that the term "critical natural gas infrastructure load" be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
Reference comment on question 1. Additionally, while EOP-011 does address the overlap between circuits designated for operator-controlled manual or automatic Load shedding and those used for UFLS/UVLS, RF recommends requirements to prioritize certain circuits for the implementation of UFLS and/or UVLS fall under PRC-006 and PRC-010. It is not clear in the current draft of EOP-011 that the “provisions for the identification and prioritization of designated critical natural gas infrastructure loads” also apply to UFLS and UVLS programs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed the option of making modifications to PRC-006 and PRC-010 and determined that it was not necessary and would be most appropriate to keep these load shed requirements in one location. Each of the sub-requirements under 1.2.5	

intentionally utilizes the term "provisions." This term, which has been carried forward from EOP-011-2 and EOP-011-3, is intended to mean that it is the responsibility of the Transmission Operator to work with other entities, as necessary, to ensure that their operating Plan is responsive to these requirements. To ensure that all Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners are aware of any new responsibilities the SDT has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes. Additionally, changes were made to R1.2.5, R2.2.9, and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Again, the changes do not identify how or who will be responsible for determining and identifying the critical natural gas infrastructure.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Please see BPA's response to Q1 and Q3 above.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Coordination between the Electric industry and the Gas Industry in terms of communication and operational obligations must be sufficient to fully apply the intent of EOP-011-4. Until clear guidance of communication and the coordination can be provided – either through standard modification or assigned entity responsibility – FirstEnergy cannot support the proposed treatment of critical natural gas infrastructure in manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	

Comment	
The changes do not provide sufficient clarity of what constitutes critical natural gas infrastructure. ATC requests that the term "critical natural gas infrastructure" be defined. Additionally, ATC requests that the definition, at a minimum, state "critical natural gas infrastructure" is natural gas infrastructure that if rendered unavailable would adversely impact the reliable operation of the Bulk Electric System. *With the addition of "automatic" to R1.2.5, the standard unintentionally conflicts with the new NERC paradigm that recognizes the role of the Planning Coordinator (PC) in the design and implementation of UFLS under PRC-006 and the PC and the Transmission Planning in the design and implantation of UVLS under PRC-010. Years ago, the load shedding requirements for the operating horizon listed both manual and automatic load shedding. However, automatic load shedding was removed due to recognition that the TOP and/or the BA do not design or implement automatic load shedding schemes. With the reintroduction of the term "automatic", this standard will now require the TOP and/or BA to be directly involved in the design and deployment of automatic load shedding schemes developed by these other entities. If the intention of the SDT is to capture automated schemes developed with a TOP or BA EMS to aid the manual load shedding process, additional language is needed to ensure the appropriate scope is understood by all parties either auditing this standard or seeking to be compliant under this standard.*	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The SDT discussed the option of making modifications to PRC-006 and PRC-010 and determined that it was not necessary and would be most appropriate to keep these load shed requirements in one location. Each of the sub-requirements under 1.2.5 intentionally utilizes the term "provisions." This term, which has been carried forward from EOP-011-2 and EOP-011-3, is intended to mean that it is the responsibility of the Transmission Operator to work with other entities, as necessary, to ensure that their operating Plan is responsive to these requirements.	
Alison MacKellar - Constellation - 5	

Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
We would like to see a requirement for the RC to identify the overlap requirements for MLS and UFLS.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R3 requires the Reliability Coordinator to review Operating Plan(s) submitted by a Transmission Operator or Balancing Authority.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
EEI agrees that the proposed changes to EOP-011 provide sufficient clarity and flexibility in regard to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	

Answer	Yes
Document Name	
Comment	
PNM agrees that there is sufficient clarity and flexibility for critical natural gas loads in regards to load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company would suggest language changes that would require coordination between natural gas facility owners and the responsible functional entities to identify Critical Natural Gas Infrastructure loads. Southern Company would modify requirement R7, subpart 7.1.5 to the following: "7.1.5 Provisions for the identification and prioritization of designated critical natural gas infrastructure loads, as identified by the responsible natural gas infrastructure owner/operator in coordination with the applicable Functional Entity. **TOP-002-5 (Questions 5-6)** **Recommendation 1g of the Report states: The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators, and Balancing Authorities in determining the generating unit capacity that can be relied upon during "local forecasted cold weather," in TOP-003-5:**	

- **Based on its understanding of the "full reliability risks related to the contracts and other arrangements [Generator Owners/Generator Operators] have made to obtain natural gas commodity and transportation for generating units," each Generator Owner/Generator Operator should be required to provide the Balancing Authority with data on the percentage of the generating unit's capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather".**
- **Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of total generating capacity that it can rely upon during the "local forecasted cold weather," and share its calculation with the Reliability Coordinator.**
- **Each Balancing Authority should be required to use its calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Real-time monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans. (Report Key Recommendation 1g)**

As explained by the Report on the 2021 event, Key Recommendation 1g was intended to "take the next logical step [after TOP-003-5 and EOP-011-2 changes take effect in April 2023] and eliminate doubt about which entity is responsible to provide information or act on information," preventing BAs and RCs from being surprised during extreme cold weather events (See Report at pp 189-190). The SDT would like feedback on the first bulleted subpart of Key Recommendation 1g, which, in essence, recommends a requirement that the GOs/GOPs provide the BA with the generating units MWs, including MWh the GO/GOP reasonably believes that it can rely upon during the local forecasted cold weather.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) agrees that the proposed language in R1.2.5.5 and R7.1.5 provides sufficient clarity and flexibility in regards to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes

Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CEHE agrees that the proposed changes to EOP-011 provide sufficient clarity and flexibility in regard to the treatment of critical natural gas infrastructure in operator-controlled manual Load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP agrees that clarity and flexibility have been added to EOP-011, however we still believe registration of natural gas infrastructure owner and operators themselves, with the RTOs in an official capacity, would add more clarity and improve overall system reliability associated with natural gas service to generating facilities. Because the proposed revisions do not include natural gas owners and operators as new Functional Entities, AEP has chosen to vote Negative on EOP-011-4.

The word “critical”, as used in lower case to qualify both loads and natural gas infrastructure loads, is subjective and subject to interpretation. This will likely result in an inconsistent application of the term across entities. AEP suggests that clarity be provided as to how to properly identify loads, including natural gas infrastructure loads, as “critical.”

Similar to our response to Question #3, we believe it would beneficial to have a criteria of critical levels similar to that used by Transmission Planning to illustrate the different risk levels. Potential examples might include 1) generation on-site backup, 2) critical to generation supply for loss of one site 3) becomes critical if electrical supply were lost at two sites in area (indicates a combination), and 4) critical to generation supply for loss of three sites and so forth. The criteria used could also capture risk to one RTO area as opposed to affecting multiple RTO regions via the interstate pipeline system. We believe it would be beneficial for NERC to work directly with FERC and gas suppliers to develop this set of criteria to assist in properly identifying risk.

AEP believes clarity is needed regarding scenarios when the Distribution Provider and the Transmission Operator are not within the same company. For those situations, it is unclear how self-identification would occur and what their obligations might be.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Additional content has been added to the Technical Rationale to address this topic. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.

The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The potential criteria of critical levels in your comment represents a reasonable approach that entity may choose to take in crafting their prioritization approach in 1.2.5.5 or 8.1.5. To ensure that all Distribution Providers, UFLS-Only Distribution Providers, and Transmission Owners are aware of any new responsibilities the SDT has added a new R7 and modified R8 to include the concept of identification and notification. Please see the Technical Rationale for additional explanation of these changes.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	

Yes. The changes in EOP-011 and the supporting technical rationale provide sufficient clarify and flexibility.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	

No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends the requirement apply to any manual or automatic load shed programs. The term “Interruptible Load” references the inactive LSE function. The other terms, curtailable Load and demand response, are not defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to Question 1.	

See the unofficial comment form for additional information: https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07_Cold_Weather_Phase%202_Unofficial_Comment_Form_02282023.docx

5. Please comment on whether information pertaining to the generating unit's MWs, including MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather, would be useful to your operations during local forecasted cold weather. Alternatively, is there a better way for the BA to develop assumptions related to cold weather needs to address this specific metric rather than asking for this information from the GO/GOPs? Please provide comments and revisions to the draft language.

Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
No, CEHE supports the comments as submitted by Edison Electric Institute and agrees the GO/GOP would be the best source for the reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) supports Edison Electric Institute's comment and agrees the GO/GOP would be the best source for the most reliable projections.	

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to EEI.

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

Answer	No
Document Name	

Comment

Southern Company agrees with EEI comments that The GO/GOP would be the source for the most reliable projections. Southern Company would add that providing the MWhs is not helpful. The anticipated schedule for the 5-day period would be more useful, along with additional MWhs available above the projected schedule, only if availability limitations exist.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to EEI. The SDT appreciates the input on the need to adjust the standard as needed.

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	

Comment

BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.

Likes 0	

Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
BHP as TOP, amount of MWh is not useful for BHP as a TOP. More interested in if a unit is or is not available which we would have through new cold weather standards with TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
The requested generator data is only as good as the availability of the natural gas supply. More needs to be done to ensure supply meets and or exceeds demand and or increase generation of other available resources to make the industry and generation reliable. In addition, BAs, particularly in organized markets, need greater certainty from the GOs as to the need for their resources during projected periods of extreme cold weather. In this regard, market operators need to be held accountable for a greater level of precision in load forecasting so that gas supply can be procured in advance more thoughtfully and not as a result of wildly inaccurate estimates. Where is the	

added accountability on the market operators for improving its processes? A significant amount of the 'emergency' in December 2022 could have been averted by better load forecasting and generation scheduling practices at the ISO/RTO level.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Market operation recommendations are outside of the scope of the SAR. Please see the FERC recommendation report for recommendations related to market operations.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
APS believes that information pertaining to the generating unit's MWs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would be useful to our operations during local forecasted cold weather. APS does not believe that information pertaining to the generating unit's MWhs the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would be useful to our operations during local forecasted cold weather. APS agrees that the GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and the SDT did not adjust the standard to add MWhs.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No

Document Name	
Comment	
The GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Ameren perfers not to make assumptions on the performance of generators during cold weather events. We believe that MISO may be better suited to provide this information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the responsibility of the GO/GOP to understand and communicate this information to the BA. The GO/GOP would be the source for the most reliable projections	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

This information is already required to be provided with the update to TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
The proposed approach is unlikely to result in useful information. While owners and operators of some simpler facilities with hard cutoff protection, such as wind turbines, may be able to forecast cold weather performance with some degree of certainty, more complex facilities,	

such as thermal generation facilities, have many, many variables that impact cold weather performance and make it difficult for owners and operators to accurately forecast cold weather performance.

Older units may have had several retrofits that make a design limit highly inaccurate. A thorough, recently conducted engineering analysis can provide more accuracy than original design limits; however, even these types of analyses will lose accuracy over time as generating units suffer degradation and are retrofitted. Even recent historical performance will become less dependable over time and is inherently limited to temperatures actually observed. Historical performance data also may not capture the impact of maintenance or upgrades undertaken to address previous performance failures.

In addition to the limitations of performance limit calculations, there are also inherent inaccuracies in the temperature forecasts used to attempt to determine the limits that may apply during an upcoming event, as these forecasts may be based on information from weather stations many miles away from a given generating facility. Fuel supply and inventory information also depend on natural gas suppliers providing timely and accurate notifications to GOs and GOPs. RCs and BAs ultimately depend on information that other entities provide to them and will continue to encounter scenarios where unit performance does not conform to provided limits and where units suddenly identify fuel constraints as an event unfolds because their fuel provider did not provide sufficient advance notice of fuel supply constraints.

Given these inherent inaccuracies and uncertainties in availability forecasts, a forecast from a GO or GOP that a unit is going to be fully or partially unavailable would only be useful to a BA if the unavailability is certain; forecasts based on potential risks or potential unavailability are not typically useful to BAs. Generating units preemptively coming offline because of anticipated cold weather is counterproductive unless there is a need to protect equipment. All of this taken together means that information pertaining to a generating unit’s MWs, including MWhs, the GO/GOP reasonably believes that the BA can rely upon during local forecasted cold weather would not be useful to the operations of ERCOT during local forecasted cold weather.

A more effective approach would be to require GO/GOPs to provide BAs with data about specific constraints that might limit the capabilities of their units, such as known fuel and emissions constraints, and allow each BA the leeway to develop its own approach and assumptions related to cold weather needs based on its past experiences and the unique characteristics of its Balancing Authority Area.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. While the team discussed inclusion of the recommend constraints, they did not adjust the drafted standard to include them. The SDT believes it has accomplished the intent of your suggested approach with proposed R8. To the extent that the BA needs additional information from the GO/GOP to implement its Operating Process, that is covered under the data specification in TOP-003.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
It does not seem practical for plants to guess at what they expect they can do during cold weather. They already have to plan to fully perform during expected cold weather based on past history. Why would anyone expect, or rely on, anything other than 100% performance. That is what we design the system to (Ten Year Site plans, long term forecasts, etc.). The standard appears to only penalize an entity if they have another Winter Storm Uri, which we of course do not want it to happen again. It seems unnecessary to double the size of all our generators and transmission lines so we can operate to the unforeseen failure of so many things all at once. We are making progress, but this standard has many ways to meet an entities needs and very few ways to succeed short of another Uri and not having any issues.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The intent of the SAR and requirements is not to create penalties based on storm status. The intent is the useful flow of relevant information so that the BA can manage its footprint during a cold weather event and there is no suggestion or requirement to implement the investments in generator output or transmission capability. Proposed R8 is structured to promote data exchange between the GO and BA to allow the BA to create processes to aid in the management of cold weather periods.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes

Document Name	
Comment	
MISO is Entergy's Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
The expected generation is important for performing an accurate Operational Planning Analysis, OPA. BA's determine generation resource commitment based on generation limitation derates and outages in the outage management system, per TOP-003 and IRO-010. Due to the	

recent additions in TOP-003 and IRO-010 to specifically identify cold weather limitations of generators this is already integrated into OPAs and real-time assessments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
SDT may want to consider that it may be useful to areas where wholesale electricity markets are not operating, to propose a requirement to have the GO/GOP to provide its BA with a reasonable forecast pertaining to its generating unit(s)' forecasted MW/MWh output during local forecasted cold weather so the BA can use this information when developing its five-day hourly forecast for their BA footprint.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	

PNM's assessment is that MW forcasting from generators should come from the GO/GOP. PNM supports EEI comments that the GO/GOP would be the source for the most reliable projections.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to NSRF comments.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

The BA already has the tools and the authority necessary to plan for generating unit MWH. There is no need for another process, except to define “critical natural gas infrastructure load” and add it to the plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
We believe this data would be beneficial and should be supplied by the GO/GOP to the BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
No Additional Comments	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments to assist the SDT on drafting the standard.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
WAPA believes it would be useful to BA operations to have the GO/GOP, in accordance with the BA's documented methodology, provide a reasonable five-day hourly forecast of MW or MWh output for each generating unit during local forecasted cold weather so the BA can incorporate this information into the five-day hourly forecast for their BA footprint.	

WAPA believes what is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors (including the weather forecast) change in real-time, thereby altering the energy output forecast. WAPA recommends the GO/GOPs provide their BA with a reasonable forecast to work with. WAPA supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA as: 1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not ony does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected conditions 2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment. Without this information, the BA must employ manual methods (e.g. phone calls) to gather this information anecdotally.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees that GOs should not be penalized for providing a reasonable forecast and have structured the requirements to not require such. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Response to the question regarding MW/MWh data being useful to operations: This question will receive varied responses depending on the functional registrations of the respondent, but as a GO/GOP/TO/DP, this information would be useful to us as we will use this information as an indication of potential Emergency situations, assuming that we will be receiving notice prior to cold weather event rather than just prior to the season. As a GO/GOP in ISO-NE territory, we would consider self-scheduling some or all of our thermal resource's capability to mitigate	

the impact of a potential pay-for-performance (ISO-NE market construct that is triggered when reserve deficient) event. As a DP, this will allow us to better prepare for manual load shedding, such as calling in additional staff to prepare for rotation and restoration of outages	
Likes 0	
Dislikes 0	
Response	
The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The SRC[1] believes it would be useful for GO/GOPs to provide their BAs with a reasonable forecast of their generating unit(s)' MW/MWh output during local forecasted cold weather so the BA can use this information when developing its five-day hourly forecast for its BA footprint. In the absence of a generator output forecast, the Balancing Authority might attempt to create its own forecast using the information it has available, such as historical generator performance; however, this would only represent a BA's best guess, which would still be less informed and less accurate than a forecast created by a GO/GOP for its own unit(s). The SRC proposes that the GO/GOP would provide the BA with an hourly forecast of their expected energy output for the following reasons: 1. **GO/GOPs are in the best position to prepare an educated forecast for their generating units' output.** The GO/GOP will have more detailed past performance data than the BA will have, along with superior knowledge of how their unit will likely perform under expected weather conditions. The GO/GOP will also have more intimate knowledge of their fuel supply and inventory, start-up concerns, environmental limitations, and other factors listed in Part 8.2.	

2. **A BA that receives a more accurate output forecast will be in an improved position to increase the accuracy and strategy of its unit commitment and dispatch.** With the information from the GO/GOP described above, the BA will be in an improved position to determine when to deploy the generating units in its footprint. In addition, it will minimize the burden on the BA to employ manual methods, such as phone calls, to gather this information anecdotally. In order for this approach to function properly, it is critical that this requirement be established under a framework like that used for load forecasting. Specifically, GO/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors will emerge and existing factors, such as the weather forecast, will change in real-time, thereby causing the actual energy output realized to diverge from the forecasted output [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA. The SDT believes it has crafted standards that allow the BA to receive such information from the GOs and other information as well to utilize in its Operating Process to manage cold weather periods. The SDT agrees GO' should not be penalized for failure to achieve complete accuracy and has not included such a requirement in the proposal.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Capability of generating units is necessary for BAs to develop Operating Plans, regardless of weather conditions. It is the sole responsibility of the GO/GOP to understand and communicate this information to the BA.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	

Abstain	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to IRC SCR.	

Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A to Hydro One	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	

Comment	
PacifiCorp holds that through existing processes, BAs possess the needed means to collect all information necessary to make determinations about generation availability during local forcasted cold weather. Currently, PacifiCorp sees a reliability gap between what Generator Owners (GOs) /Generator Operators (GOPs) offer into the market and the amount of energy (MWh) that shows up in real-time. PacifiCorp's Risk Assessment Team analyzes this gap and attempts to close it using the information we have available; e.g. historical generator performance, to develop a "best guess" forecast for generator output. At best, our guess is uncertain. Rather than requiring the BA to put on the hat of a generator and attempt to make an educated guess on their behalf, what we would like to see is something akin to what is done with load forecasting. PacifiCorp supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA for the following reasons: 1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not ony does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected conditions; e.g. if a GO/GOP has been told by their natural gas supplier that there is a 50% chance that their natural gas supply will be curtailed, the GO/GOP could incorporate this information into their energy output forecast. 2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment. Without this information, the BA must employ manual methods (e.g. phone calls) to gather this information anecdotally. What is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors change in real-time, thereby altering the energy output forecast. PacifiCorp recommends the GO/GOPs provide their BA with a reasonable forecast to work with.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA. The SDT believes it has crafted standards that allow the BA to receive such information from the GOs and other information as well to utilize in its Operating Process to manage cold weather periods. The SDT agrees GO' should not be penalized for failure to achieve complete accuracy and has not included such a requirement in the proposal.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	Q5-6.PNG
Comment	
The MRO NSRF believes it would be useful to BA operations to have the GO/GOP, in accordance with the BA's documented methodology, provide a reasonable five-day hourly forecast of MW or MWh output for each generating unit during local forecasted cold weather so the BA can incorporate this information into the five-day hourly forecast for their BA footprint. The MRO NSRF believes what is critical to making this work is a framework similar to that for load forecasting. GOs/GOPs should not be penalized for failure to predict their energy output with complete accuracy. There should be some recognition that new factors can emerge or existing factors (including the weather forecast) change in real-time, thereby altering the energy output forecast. The MRO NSRF recommends the GO/GOPs provide their BA with a reasonable forecast to work with. Currently, MRO NSRF sees a reliability gap between what Generator Owners (GOs) /Generator Operators (GOPs) offer into the market and the amount of energy (MWh) that shows up in real-time. In part this is due to the fact that generators do not know in advance how many hours they will be dispatched to run, thereby making it difficult for them to reflect when they expect to "run out of fuel" in their forecast.	

A MRO NSRF member's Risk Assessment Team analyzes this gap and attempts to close it using the information we have available; e.g. historical generator performance, to develop a "best guess" forecast for generator output. That said, our "best guess" is still uncertain. Rather than requiring the BA to put on the hat of a generator and attempt to make an educated guess on their behalf, what we would like to see is something akin to what is done with load forecasting. The MRO NSRF supports a framework that would ask GO/GOPs to provide their forecasted energy output information to the BA for the following reasons: 1. GO/GOPs are in the best position to provide an educated forecast for their units' performance. Not only does the GO/GOP have superior past performance data (over that of the BA) to perform this analysis, they also have superior knowledge of how their unit will likely perform under projected weather conditions; e.g. if a GO/GOP has been told by their natural gas supplier that there is a 50% chance that their natural gas supply will be curtailed, the GO/GOP could incorporate this information into their energy output forecast. 2. BAs receiving a more accurate output forecast would be in an improved position to increase the accuracy of their dispatch and unit commitment. With the information from the GO/GOP described above, the BA will be in an improved position to determine when to deploy the generating units in their footprint. In addition, it will reduce the need for the BA to employ manual methods (e.g. phone calls) to gather this information anecdotally.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thank you for your comment. The SDT did not require this due to majority of respondents commenting on there was no need for MWh provided to the BA. The SDT believes it has crafted standards that allow the BA to receive such information from the GOs and other information as well to utilize in its Operating Process to manage cold weather periods. The SDT agrees GO' should not be penalized for failure to achieve complete accuracy and has not included such a requirement in the proposal.	

6. Recommendation 1g, bullets 2 and 3 of the Report suggests that each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator to determine total generating capacity that can be relied upon during "local forecasted cold weather," and utilize such information to "prepare its analysis functions and Real-time monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans." The SDT proposes a new Requirement R8 in TOP-002 that requires a Balancing Authority to create an extreme cold weather Operating Process within its Operating Plan to formalize the Balancing Authority's analysis functions and Real-time monitoring of its Balancing Authority Area during extreme cold weather. Do you agree the language in proposed Requirement R8 of TOP-002 addresses the intent of and is the appropriate manner in which to satisfy Recommendation 1g? Please provide the reasoning or justification for your position in the comments.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
We are of the opinion that the analysis is not needed. If we come up negative, we already have a Capacity Emergency Procedure. It does not have to be a stand alone "Cold Weather" Capacity Emergency Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to SRC.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed your comment and decided, based on the scope of the SAR and FERC's recommendations, that a specific requirement for an operating process is appropriate in this case.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment	
Requirement R8 as written only partially addresses the intent of Recommendation 1g While Requirement R8 addresses a *portion* of the intent of Recommendation 1g (bullets 2 and 3), the SRC believes it is insufficient to achieve the overall intent of Recommendation 1g without a corresponding requirement for GO/GOPs to provide BAs with their output forecasts (bullet 1). Without a corresponding requirement for the GO/GOP to provide its BA with an expected output forecast for its unit(s), there may be a reliability gap in terms of what the BA can generate to comply with Parts 8.2 and 8.3 as described in the SRC's response to Question #5. The GO/GOP is in a superior position to provide the information listed in Part 8.2. Therefore, for the BA to develop a methodology that considers these operating limitations, there must be an equal and opposite requirement for the GO/GOP to provide this information to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an *hourly* generator output forecast for *five days* into the future. **There is a mismatch in time horizons for the Operating Process (R8) and Operating Plan (R4)** The SRC supports the proposal of a flexible, methodology-based approach to identifying an extreme cold weather period; however, the SRC believes the proposed language in Requirement R8 conflicts with the language in Requirement R4. Under the proposed language, R8 and R4 both reference the Operating Plan; however, R4 contemplates the Operating Plan as applying to next-day operations only, while R8, Part 8.3 specifically requires a "five-day hourly forecast." To rectify this mismatch, the SRC proposes the following modification: **R8.** Each Balancing Authority shall have an extreme cold weather Operating Process, *to inform* its Operating Plan developed in Requirement R4, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT reviewed your comment as part of the discussions and determined, based on a number of industry comments, to delete the link with the Operating Plan and have the Operating Process be a stand-alone requirement that is supplemental. The SDT believes the BA is equipped with the necessary ability under data specification requirements to receive the data from the GOs and has built flexibility into the requirement to allow the BA to manage its footprints under its own developed methodologies, rather than dictating with specificity.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed your comment and decided, based on the scope of the SAR and FERC's recommendations, that a specific requirement for an operating process is appropriate in this case.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

There are redundancies between this language and TOP-003-5 and EOP-011-2. This language also adds additional data requirements not included in TOP-003-5. TOP-003-5 does not include data related to generation start failure. TOP-002-5, R8 part 8.2.3 (Start-up issues) is not included in TOP-003-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed this and chose not to include that information in TOP-002 R8. The SDT believes that TOP-003 gives the BA the ability to ask for any information they deem necessary.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports TPWR comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to TPWR.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Most of the requirements in R8, such as reserve margin, fall under the responsibility of our BA which is MISO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed your comment and decided, based on the scope of the SAR and FERC's recommendations, that a specific requirement for an operating process is appropriate in this case.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	

Comment	
Including a requirement for a BA to have a methodology to identify an Extreme Cold Weather period in their area seems to be a good fit for the recommendation. Proposed Requirement 8.3.1 states, "expected generation resource commitment and dispatch" with regards to a five-day hourly forecast. Generation resource commitments are typically done as a function of the markets and are done in the day-ahead time horizon. While some baseload generation is capable of being projected, many other intermittent and self-scheduled peaking facilities are much more difficult to accurately project, especially beyond a couple days. The SDT should consider changing requirement 8.3.1 to "Anticipated available resources" as resource commitment and dispatch are typically viewed as operating day or day-ahead activities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT discussed and determined that R8.3 is intended to be a longer time horizon rather just day-ahead. Additionally, the SDT determined that the words "expected" and "anticipated" are interpreted similarly and opted to retain the term "expected." While the SDT understands that markets optimize the costs, the BA has a reliability function to ensure generation and loads balance.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	

For TOP-002-5 Requirement 8.3, Tacoma Power is unsure whether this Requirement is for the BAA or for each generating unit. Tacoma Power recommends modifying the Requirement 8.3 to specify whether it's applied to BAA or each generating unit. For example, "A methodology to determine a five-day hourly forecast **within each Balancing Authority Area** during the identified extreme cold weather periods that includes..."	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT clarified "BAA" in the main body of R8 so that it applies to 8.1 through 8.3.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
APS agrees that much on the language in R8. However, a key element in Recommendation 1g bullets 2 is missing, which is that each "Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator." We recommend the following edits to R8 in bold: Each Balancing Authority shall have an extreme cold weather Operating Process, as part of its Operating Plan, developed in Requirement R4, **that in combination with its own evaluation, utilizing resource capability and fuel availability data provided by the responsible GO/GOP, addresses** preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT determined that other standard requirements regarding plans and processes (See R4) do not have that level of detail, and rather, require the BA to have a plan or processes in place, the proposed requirements follow the same paradigm.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
IWECC believes the proposed language is relatively clear and auditable but there is some question about when this cold weather operating process should be implemented and appear in the daily operating plan. An auditor may expect to see it addressed in a daily plan during December but probably would not expect it to appear in the plan for July. But there is a possibility that unless it was addressed in the process, some auditors would expect to see a forecast and determination of cold weather considerations included in every operating plan. The requirements for when, or what triggers, the process should be included in the subrequirements for R8 to reduce the chance of an unreasonable audit approach	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has modified language of R8 and removed the tie to R4.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	No
Document Name	
Comment	

SMUD agrees with the comment provided by Tacoma Power. It is unclear whether TOP-002-5 Requirement 8.3 applies to the BA Area or to each generating unit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Tacoma Power.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
Operational Planning Analyses are conducted using temperature forecasts and expected generation resource commitment and dispatch. The process during cold weather would be no different than any other OPA. Generation limitations are identified as outages or derates in the outage management system, per TOP-003 and IRO-010.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	

As currently proposed, R8 states that each Balancing Authority's "extreme cold weather Operating Process" is to be "part of its Operating Plan developed in Requirement R4." However, R4 requires Operating Plan(s) for "the next day," implying that these Operating Plans may vary from day to day throughout the year. RF recommends R8 be revised to state that the "extreme cold weather Operating Process" is "to support the development of the Operating Plan(s) pursuant to R4." An Operating Plan developed for a day in July is unlikely to need to include an extreme cold weather Operating Process, but Operating Plans for days that may fall during extreme cold weather periods should be developed in accordance with the Operating Process, which must be available for use when needed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and has modified language of R8 and removed the tie to R4.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Per TOP-003 R4., BAs are already required to develop Operating Plans for the next-day that address expected generation resource commitment and dispatch, which require knowledge of generating units' capabilities, regardless of the weather conditions. The proposed R8 is redundant and unnecessary, as what it requires is already addressed in TOP-003-5 and TOP-002-4. Further, R8.3 is now requiring development of an Operating Plan, although it doesn't explicitly state it but it includes the same elements required in R4 with the addition of a weather forecast, for a five-day period, but only during an extreme cold weather period.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has reviewed your comment and decided, based on the scope of the SAR and FERC's recommendations, that a specific requirement for an operating process is appropriate in this case.

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	Yes
Document Name	

Comment

Without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in our response to Question #5, PacifiCorp sees a real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an hourly generator output forecast for five days into the future.

8.2 A methodology that determines an appropriate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods including:

8.2.1 Capability and availability;

8.2.2 Fuel supply and inventory concerns;

8.2.3 Start-up issues;

8.2.4 Fuel switching capabilities; and

8.2.5 Environmental constraints

8.3 A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes: 8.3.1 Expected generation resource commitment and dispatch. 8.3.2 Interchange scheduling; 8.3.3 Demand patterns; 8.3.4 Capacity and energy reserve requirements, including deliverability capability; and 8.3.5 Weather forecast	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT determined that the BA is empowered under the current data specification requirements to request and receive all necessary information needed from the GO/GOP.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
However, without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in response to Question #5, there is a real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT determined that the BA is empowered under the current data specification requirements to request and receive all necessary information needed from the GO/GOP.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
The BA already has the authority under the standards to require the GO/GOP to report any fuel supply and inventory concerns. In addition, R3 of EOP-012 requires a cold weather preparedness plan which includes "generating unit(s) operating limitation in cold weather to include:...Fuel supply and inventory concerns".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to MRO NSRF.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees the language in Requirement R8 appropriately addresses the intent of Recommendation 1g bullets 2 and 3.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM is in agreement with that language in R8.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Additional resources should be utilized to offset the demand for natural gas if that industry cannot meet demand. The 'all the eggs in one basket' approach is problematic and suggests a more thoughtful resource balance is necessary to mitigate these effects.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The requirements will provide the BA with information necessary to consider its resource adequacy needs and react accordingly.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF believes that while the proposed language for Requirement R8 of TOP-002 is appropriate to address the intent of Recommendation 1g relative to the BA's role (bullets 2 and 3) , it is insufficient to achieve the overall intent of Recommendation 1g without a corresponding requirement for GO/GOPs to provide the information described under bullet 1. Without requiring the GO/GOP to provide an expected output forecast for its unit(s) as described in our response to Question #5, MRO NSRF sees a real reliability gap in terms of what the BA will be able to generate to satisfy Parts 8.2 and 8.3 (below). The GO/GOP is in a far superior	

position to provide the information listed in Parts 8.2.1 - 8.2.5 to that of the BA. Therefore, for the BA to develop a methodology that considers those operating limitations, there must be an equal and opposite requirement on the GO/GOP to provide these limitations to the BA. The time horizon for the GO/GOP requirement must mirror the proposed BA requirement for Part 8.3; i.e. an hourly generator output forecast for five days into the future.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT determined that the BA is empowered under the current data specification requirements to request and receive all necessary information needed.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	

BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
BHP is not a BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
BHP is not a BA,	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with EEI comments that the language in Requirement R8 appropriately addresses the intent of Recommendation 1g bullets 2 and 3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support. Please see response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see response to EEI.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
N/A to Hydro One	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to IRC SRC comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE noticed the use of the term "extreme cold weather period," which is not defined in the NERC Glossary. EOP-012-1 introduced the term "Extreme Cold Weather Temperature," and it is unclear how or whether these two terms work together. Specifically, would an "extreme cold weather period" only include time periods in which Extreme Cold Weather Temperatures (i.e., 0.2 percentile temperatures) would be reached, conditions which approach, but do not reach those extremes but could have reliability impacts, operating conditions before and after such periods, and, if so, for how long? The SDT may wish to clarify these relationships. It is unclear what the expectation is for BAs that cover a large geographic area that is subject to significant differences in weather. Would the Operating Process only apply to the part of the area that is subject to the extreme cold weather? Texas RE notes that reserve margin is generally not considered in sub-areas of a Balancing Authority Area. Texas RE recommends defining the term "reserve margin" in Requirement Part 8.2. Texas RE understands that the intent of the recommendation 1g was to provide clear delineation of responsibilities and estimates of generation availability so that BAs and Reliability Coordinators (RCs) can perform real-time monitoring and managing of generating resources as part of its capacity and energy operating plans. If the SDT retains the concept of a "reserve margin" to perform this function, Texas RE believes it is appropriate to better clarify that relationship. Texas RE inquires whether the expectation is to create the five-day hourly forecast that goes beyond the "extreme cold weather period' per Requirement part 8.2. For example, the cold weather period defined by the BA is 24 hours of consecutive freezing weather across the entire Balancing Authority Area but is only forecasted for 2 days. Texas RE understands the current language to indicate there would need to be a five-day forecast the day ahead of the forecasted temperature (per the Operating Plan), the first day of the forecasted temperature Operating Plan and then the Operating Plan developed on second day of forecasted extreme cold weather would include the five-day forecast. Is this the SDT's intent?	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT decided to not define reserve margin as this term is used in other standards. The SDT has also clarified the intent by adding the concept of BAA to the main requirement and language of R8.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
To simplify the requirement and maintain consistency with the intent of the rest of TOP-002, BPA recommends removing the "five-day hourly forecast" requirement of R8.3. BPA suggests the intent of Recommendation 1g would be satisfied by modifying R8.3 to state: **"A methodology to include the extreme cold weather reserve margin determined in R8.2 when creating the Balancing Authority Operating Plan for the next-day addressed by R4."**	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.

Dislikes 0	
Response	
Thank you for your comment. Due to similar concerns expressed by much of industry, the SDT deleted the tie to R4 and has made R8 supplemental rather than a requirement for the Operating Plan.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	
Document Name	
Comment	
MISO is Entergy's Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

Thank you for your response.

7. The SDT proposes that the modifications in EOP-011-4, EOP-012-2, and TOP-002-5 meet the key recommendations in The Report in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
See our response to Q3. Until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot determine the cost effectiveness of these proposals.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the response to Q3.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
The addition of R8 in TOP-002-05 is redundant. The OPA process does not change based on the weather. Requirement R4 requires an Operating Plan, whether that plan is to mitigate impacts in a cold weather scenario or extreme summer temperatures is irrelevant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes the new R8 Operating Process is not redundant to the R4 Operating Plan.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHP will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
BHP will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
BHP will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
BHP will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments below: We believe that the identification of critical natural gas infrastructure loads should be performed at a single operating level. To require the TO, DP, DP-UFLS, TOP, and BA to all perform the same identification function(s) seems redundant and inefficient. Please see our comments for questions 3, and 4 above for additional details.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see responses to Q3 and 4.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	No
Document Name	
Comment	
Their needs to be a documented plan for generating facilities to recoup the cost for modifications and upgrades of freeze protection measures and additional layers of freeze protection measures.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. It is outside the SDT and NERC's purview to address cost recovery mechanisms.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
Until these recommendations are implemented WEC Energy Group is unable to make a determination as to the cost effectiveness of the modifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Depending on the number of identified items that require physical changes and engineering updates, these standard changes may require multiple projects on the distribution system. These projects will involve equipment that may have supply chain challenges that will add time and expense to the process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The implementation plan for EOP-011 has been extended to address some timeframe concerns.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	

Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The SRC is concerned that TOP-002-5 as written is not the most cost-effective approach since it lacks a corresponding requirement for the GO/GOP to provide the BA with their MW/MWh output forecast. Historically, SRC members (as registered BAs) have incurred additional costs when implementing BA requirements when there is not a corresponding requirement for other Responsible Entities (e.g., GOs and GOPs), to provide the BA with the information needed for the BA to perform its compliance obligation(s). This increases the overall cost of compliance, as the BA must develop and employ alternative processes to obtain the data needed (e.g., modifications to a FERC tariff, revisions to membership agreements, engagement in regional rulemaking processes, etc.). In addition to the cost of delays, there may also be costs associated with the BA receiving lower quality data than if the obligation to provide data had been enshrined in a Reliability Standard or other regulatory rule.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT did not include a requirement for the GO/GOP or the BA to request the MW/MWh information. Additionally, the SDT believes that other information required under R8 is available through a data specification.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
The coordination efforts between multiple DPs in multiple TOs area and the staffing needed to create plans, process, implement and manage is burdensome and costly to the TOPs, DPs and TOs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
We believe that the identification of critical natural gas infrastructure loads should be performed at a single operating level. To require the TO, DP, DP-UFLS, TOP, and BA to all perform the same identification function(s) seems redundant and inefficient. Please see our comments for questions 3, and 4 above for additional details.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Q3 and Q4.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
On the surface this may seem as a low cost option; however, if you delve deeper into the reason for the need for the standards, we would have to overbuild the BES for extreme events like Uri. This does not appear as cost effective. While Electricity is a critical commodity, there is a time when we will have to shed firm load. It will be during an extreme event. No one wants to, but we cannot build, economically, the infrastructure to keep this from happening.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The SDT does not believe that EOP-011 and TOP-002 do not have requirements that would be considered “overbuild”. The proposed requirement in TOP-002 is designed to provide more notice for the potential need to curtail firm load and then EOP-011 requirements are designed to improve or minimize the amount of firm load needed to be curtailed during severe events.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Question should be updated to remove EOP-012	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
We would like to see a longer implementation period with a phased in approach, 25% per 12 month period starting after 12 months to ensure a more cost effective implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Q8 regarding implementation timeframes.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
In New England, we do not anticipate severe cost increases in complying with the proposed standard revisions as our plants are built with cold weather in mind. We believe that the BA will incur the greatest cost implications in complying with R8.3 as an hourly forecast can be very involved for large systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District,	

3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE Abstains from Question 7.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	
Document Name	
Comment	
Southern Company does not think this answer will be known until everything is fully implemented.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	

No comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

8. Do you agree with the implementation plan proposed by the SDT? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends a 24-month implementation timeframe to account for the coordination, budget revisions, staffing changes, and systems upgrades necessary to accomplish the new tasks. New forecasts and tools often require multiple projects to acquire the necessary input data and to process and display that data to users. This often requires extensive testing as well.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and	

Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7. Per our recommendation for modifying R7 in response to Question 3, we recommend a phased-in implementation plan for this standard. It is our recommendation that the phased-in compliance date be no earlier than six (6) calendar months after the effective date of R1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	
Comment	
For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The SRC[1] supports an 18-month implementation timeframe for EOP-011. In addition, the SRC supports an 18-month implementation timeframe for TOP-002. (This would extend the proposed 12-month timeframe to 18 months (assuming the SDT adopts the SRC's recommendation for the GO/GOP to provide the MW/MWh output forecast as described in the SRC's response to Questions 5 and 6). This would align the implementation timeframe for all Phase 2 requirements to 18 months, ensuring all requirements would be in place prior to the Winter 2025-2026 season [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO (with the exception of our response to question 5), ERCOT (with the exception of our responses to questions 3, 5 and 8), IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	

Dislikes 0	
Response	

Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	No
Document Name	
Comment	

For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and

R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Depending on the number of identified items that require physical changes and engineering updates, this may not be possible in an 18 month period. The SDT should consider a phased approach to this implementation plan.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
Recommend aligning the implementation plans for EOP-011-4 and TOP-002-5 to 18 months.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID recommends an 18-month implementation plan.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren recommends extending the implementation plan for TOP-002-5 be extended to 18 months.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	

Answer	No
Document Name	
Comment	

For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	
Comment	

We would propose for EOP-011-4 that R7 has a later implementation date than R1 to afford those entities identified by their TOPs sufficient time to prepare and comply.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports MRO NSRF comments on the implementation timeframe.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	

Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group proposes that the implementation timeframe for TOP-002-5 be extended from 12 months to 18 months	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	

A phased in implementation approach, 25% per 12 month period, starting after 12 months.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
In support of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and	

R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

As stated in response to question #3, APS supports a phased approach for EOP-011-4 Requirement R7 that provides 18 months to identify the critical natural gas infrastructure and 18 additional months to make system and field changes. The 18-month time frame is sufficient to identify natural gas infrastructure. However, it is insufficient for TOs, DPs, and UFLS Only DPs to either move those loads to other feeders or to entirely exclude those feeders from their load shedding programs and find other suitable offsetting loads in their place. This work often requires both engineering and field crew support to fully accomplish and will likely require 36 months to fully implement.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the

first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC has signed on to ACES comments below: There is not a separate implementation phase for a newly identified DP, DP-UPFL, and/or TO. As an example, if the standard goes into effect 1/1/2025 and the TOP now identifies a DP in its Operational Plan on 1/1/2025 (per proposed Requirement R1.2.5.6), the current language and Implementation Plan seems to indicate that the DP must immediately have a plan implemented on the same day. Thus, we recommend a phased-in compliance approach for Requirement R7. Per our recommendation for modifying R7 in response to Question 3, we recommend a phased-in implementation plan for this standard. It is our recommendation that the phased-in compliance date be no earlier than six (6) calendar months after the effective date of R1.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the	

first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State suggests a 48month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	

For EOP-011, propose 36 months. The coordination and agreements between multiple DPs and multiple DP's in multiple TOs areas, could possibly take a significant amount of time. For TOP-002, propose 18 months to remain consistent with other revisions.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Implementation timeframe should be extended to at least 24 months to allow sufficient time to collect and incorporate the data. An implementation period of 36 months will allow for sufficient time to train all system operators on the updated plans.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
As stated in our response to Question #3, eighteen months would not be sufficient for these new Functional Entities to become compliant with their EOP-011 obligations. AEP instead recommends an implementation period of 36 months for EOP-011.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the	

first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
See our response to Q3. Until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot support the implementation plan for TOP-002-5.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
On behalf of the SERC GWG See above for R7. There is no timeframe issued for newly identified Distribution Providers, UFLS-Only DPs, or Transmission Owners to implement/respond to the TOP plan.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the	

first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Add language to align implementation plan timeframes to 18 months.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	

An 18 month implementation timeframe may be appropriate assuming the NERC Standard is approved through FERC on the same general timetable as the Phase 1 Standards, FERC approval approx. Feb 2024, with effective date of October 1, 2025 which would be prior to the 2025 winter period. However, the SDT should consider that based on the current status of the SDT through Phase 2 with this version of EOP-011 already at the first ballot, a 12 month timeframe might be appropriate so that if FERC were to approve the Standard in 2023, there would be the possibility of the effective date being prior to the 2024 winter period, or at least near the start of the 2024 winter period. If Phase 2 Standards revisions were to be adopted before October 1, 2023, the effective date would aling with the expected Effective date of the Phase 1 EOP-011 and EOP-012 which could eliminate a potential risk of compliance with multiple versions of the same Standard. ISO-NE does not support any implementation timeframe that goes beyond the start of the 2025-2026 Winter.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	

Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed 12 month implementation plan for TOP-002-5.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	

Answer	Yes
Document Name	
Comment	
PNM is in support of a 12 month implementation timeframe for TOP-002-5.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	
Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. You are correct on the timing change.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes

Document Name	
Comment	
Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn’t that be 2023?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. You are correct on the timing change.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn’t that be 2023?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. You are correct on the timing change.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Date on SDT timeline states NERC Board of Trustees adoption is October 2022, shouldn't that be 2023?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. You are correct on the timing change.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
12 months for TOP-003 and 18 months for EOP-011 seem reasonable. Please refer to comments on question 3.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	
Southern Company supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Yes, CEHE supports the proposed 12 month implementation plan for the TOP-002-5.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Company (SIGE) supports the proposed 12 month implementation plan for the TOP-002-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has extended the proposed implementation timeframe on TOP-002-5 from 12 months to 18 months to address industry concerns	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees with the Implementation Plan for TOP-002-5 but disagrees with the Implementation Plan for EOP-011-4. Please also see BPA's response to question 3.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and	

R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.	

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Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

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Julie Hall - Entergy - 6, Group Name Entergy

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements.

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Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	

No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8, R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has modified the proposed EOP-011-4 implementation timeframe to allow 30 months after the effective date of the standard for entities to implement changes necessary to meet the new and modified requirements in R1.2.5, R2.2.8,	

R2.2.9, and R8. This provides 12 additional months from the previously proposed implementation plan of 18 months. This change was made to provide adequate time for physical changes that may be required to comply with these requirements. The 30-month implementation timeframe for entities subject to Requirement R8 will not start until they are notified by the Transmission Operator per Requirement R7. Transmission Operators must provide this notification upon the effective date of EOP-011-4 which is on the first day of the first calendar quarter that is six months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
WECC leaves comment on the implementation plan to those entities that have to implement the standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	

Dislikes 0	

Response
Thank you for your comment. Please see response to EEI.

9. Is there any part of the proposed requirements, as currently drafted, that is unclear? If so, how would you make it clearer?	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
While the proposed requirements we feel are clear, until we gain full understanding of the assigned obligations related to identifying and implementing these recommendations and the TOP and BAs response toward these modifications, FirstEnergy cannot support these modifications.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Gordon Joncic - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No

Document Name	
Comment	
No.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM believes that changes are described sufficiently.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates the comments of the Edison Electric Institue (EEI) to question #9,	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment	
EEI agrees that the proposed changes to EOP-011 and TOP-002-5 are sufficiently clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Gul Khan	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Carly Miller - Carly Miller On Behalf of: Sheila Suurmeier, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 3	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ken Habgood - Seminole Electric Cooperative, Inc. - 4	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
On behalf of the SERC GWG For R7: The requirement states “The Operating Plan(s) shall be provided to the Transmission Operator.” Should this be “as requested by the Transmission Operator”? Does the TOP really want to be flooded with every DP’s full operating plan?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has clarified the wording to “shall provide the associated Load shedding plan” to limit data flow to the TOP.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	

Comment	
As metioned in the response to question 4, the standard does not define what is meant by “critical natural gas infrastructure”. ATC requests that the term “critical natural gas infrastructure” be defined.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company would clarify language in EOP-011-4 R1.2.5 that currently could be confusing regarding operator controlled MLS and automatic UFLS/UVLS as follows: “Operator-controlled **Manual Load Shed and/or Automatic Load Shed** during an Emergency that accounts for each of the following:” Southern Company would also suggest language modifications to TOP-002-5 R8 to reduce confusion in the BA having a process and having next day plans as follows: “Each Balancing Authority shall have an extreme cold weather Operating Process, **which it uses in developing** its **next day** Operating Plan **consistent with** Requirement R4, addressing preparations for and operations during extreme cold weather periods.”	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Regarding the comment on EOP-011, changes were made to R1.2.5, R2.2.9, and R8.1 to more consistently address operator-controlled manual Load shedding and automatic Load shedding. Regarding the comment on TOP-002, the SDT reviewed your comment as part of the discussions and determined, based on a number of industry comments, to delete the link with the Operating Plan and have the Operating Process be a stand-alone requirement that is supplemental.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Please refer to comments on questions 1 and 4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, please see responses to Q1 and 4.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	

More clarification is needed on the phrase "minimize the overlap" in EOP-011 Requirements 7.1.2 and 7.1.3.. How will an entity determine if it has minimized the overlap enough to satisfy an auditor and meet the expectation of the requirement?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT believes the wording is sufficient to meet most situations and does not want to be overly prescriptive in limiting how an entity meets the requirements. Additionally, the team did not modify the language "minimize the overlap" during this draft. Please see the Technical Rationale for additional information.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
See previous comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	

See earlier comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
The term “critical natural gas infrastructure” needs to be defined with a formal definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes

Document Name	
Comment	
Please see the response to question 1. WECC believes that more clarity to EOP--11-4 on identification of "critical" natural gas ficility load is possible.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
APS believes that clarification is needed in EOP-011-4 because responsible entities do not have the visibility to identify such loads, so they are reliant on natural gas facilities owners, however, natural gas facility owners have no regulatory obligation to self-identify their facilities as critical. To address this concern, APS suggests modifications to Requirement 1, subpart 1.2.5.5 and Requirement R7, subpart 7.1.5 as follows: Requirement 1, subpart 1.2.5.5: Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**; and Requirement R7, subpart 7.1.5:	

Provisions for the identification and prioritization of designated critical natural gas infrastructure loads**, as identified by the responsible natural gas infrastructure owner/operator**.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The identification and prioritization of critical natural gas loads requires coordination with natural gas facility owners and operators. The SDT recognizes that entities are dependent upon the cooperation of natural gas facility owners and operators to complete this task. However, it is outside the scope of the SDT to develop methods to compel natural gas owners and operators to cooperate and provide specific information to various entities.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
We would like more clarification on what is a “Designated Critical Load”. Many standards have overlapping definitions so a clear definition of what this means would support a consistent application.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making “critical natural gas infrastructure load” a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	

Answer	Yes
Document Name	
Comment	
Please refer to the comments in response to Question #10.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to Q10.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
See previous comments submitted on TOP-002 Requirement 8.3 and definition of critical natural gas infrastructure in EOP-011 R1.2.5.5.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comments. Please see previous responses from the SDT.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Document Name	
Comment	

The SDT should consider that the current and proposed language of EOP-011 R1 does not prevent an entity from having critical gas infrastructure loads or a designated critical load from being included in its automatic load shed circuits. Although the intent is there, the standard doesn't explicitly address that potential overlap. Recommend adding automatic to R1.2.5.2

The proposed R1.2.5.5 is specific to "critical gas infrastructure load". The SDT should consider that this be rewritten to be more generic to encompass all "designated critical loads" and not just for gas infrastructure? Does this make sense to specifically call it out in a separate requirement.

The SDT should consider whether or not to include a new term in the NERC Glossary of "Designated Critical Load" which would define what the standard critical loads are, including, but not limited to critical gas infrastructure, critical fuel delivery infrastructure, off-site nuclear feeds, public safety, public health, etc.

These specifics could be called out in the sub requirement as well.

Suggested R1.2.5 Language for additions of "automatic" to 1.2.5.2 and the specific critical loads to 1.2.5.5.

Option 1:

1.2.5. {C}Operator-controlled manual load shedding or automatic load shedding during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual and automatic Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.; 1.2.5.5. Provisions for the identification and prioritization of designated critical loads, including; 1.2.5.5.1. Natural gas infrastructure, 1.2.5.5.2. Other fuel supply infrastructure, 1.2.5.5.3. Public safety and public health infrastructure 1.2.5.6. {C}Provisions for the identification of Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners required to mitigate operating Emergencies in its Transmission Operator Area. Option 2 for R1.2.5.5 with "Designated Critical Load" glossary term: 1.2.5.5 Provisions for the identification and prioritization of designated critical loads The SDT should consider the above recommendations be incorporated into R7 for the DP and UFLS-Only DP Requirement as well since the same comments apply.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint. The team has added "automatic" to Part 1.2.5.2.	

Thank you for your suggestions on "Designated Critical Load" and the proposed standard requirement changes. The SDT has determined this is out of scope of this teams SAR and chose to maintain the separate provisions related to the identification and prioritization of critical natural gas infrastructure in 1.2.5.5 and 8.1.5.	
Kimberly Bentley - Kimberly Bentley On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	Yes
Document Name	
Comment	
Define "critical natural gas infrastructure" as be used in the requirement	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
See previous question responses.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Please see response to previous questions.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

In order to streamline R1, the SRC recommends that Part 1.2.5.5 be consolidated with Part 1.2.5.2 as follows:

1.2.5.2 Provisions to *identify and* minimize the overlap of circuits that are designated for manual *or automatic* Load shed and circuits that serve designated critical loads*, including known critical natural gas infrastructure loads*;

EOP-011, Requirement R7

The SRC is concerned with the use of the proposed language "Operating Plan," in Requirement R7, as it may be read to assign UFLS-Only Distribution Providers and Transmission Owners real-time operational tasks that they are not equipped to handle. Therefore, the SRC recommends R7 be modified as indicated below:

R7. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner identified in a Transmission Operator's Operating Plan(s) to *assist with* mitigat*ing* operating Emergencies in its Transmission Operator Area shall, *in consultation with the Transmission Operator, develop, maintain, and implement, and provide to the Transmission Operator an Operator-controlled manual, or automatic Load shedding program, that accounts for each of the following,* as applicable:[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

7.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

7.2. Provisions to *identify and* minimize the overlap of circuits that are designated for manual *or automatic* Load shed and circuits that serve designated critical loads, *including known critical natural gas infrastructure loads*;

7.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); *and* 7.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please refer to the SDT's response to your previous comments.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
See our previous comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question. Additionally, ERCOT refers the SDT to its response to question 2 to highlight the need to clarify the obligations of TOs and other applicable entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please refer to the SDT response to question 2.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to EEI.	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to IRC SRC.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

10. Provide any additional comments for the SDT to consider, including the provided technical rationale document, if desired.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) in response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to IRC SRC.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
We believe the proposed modifications are a good first attempt at meeting the identified key recommendations; however, we also believe that there are a few key areas that need additional review and clarification. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments.	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
If the SDT does not accept the SRC's recommendation to define the term "*critical natural gas infrastructure load,*" as discussed in the SRC's response to Question 1, the SRC requests the SDT include guidance on implementing this concept in the technical rationale for the Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has elected to add clarifying language in the applicable requirements and expand content in the Technical Rationale in lieu of making "critical natural gas infrastructure load" a defined term, providing flexibility for individual entities to apply this term in a manner that is appropriate for their situation. A definition may have necessarily been overly broad and would not provide substantial additional clarity given the diversity of these types of facilities throughout the BES footprint.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
Please consider updating TOP-002-5 Section C. Compliance with the most recent NERC wording used for Section C. Compliance.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has updated this wording in the posted draft.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	

Document Name	
Comment	
In Technical Rationale for EOP-011-4, the word “load” is both capitalized and not capitalized throughout the document. IID recommends the SDT check the capitalization of “load” and ensure it’s consistent throughout the document	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed the technical rationale and fixed the inconsistent capitalizations.	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	

Comment	
In the Technical Rationale for EOP-011-4, the word “load” is both capitalized and not capitalized throughout the document. Tacoma Power recommends the SDT check the capitalization of “load” and ensure it’s consistent throughout the document.	
Likes 1	Public Utility District No. 1 of Snohomish County, 4, Martinsen John D.
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed the technical rationale and fixed the inconsistent capitalizations.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
• There appears to be a correlation between EOP-011-4 R1 and EOP-001-4 R7, however there does not appear to be a similar correlation referencing obligations for others for EIP-011-4 R2. • EOP-011-4 R2 is redundant with TOP-002-5 R8. Suggest language modifications to TOP-002-5 R8 to reduce confusion in the BA having a process and having next day plans. • In EOP-011-4 R7.1, DP is being obligated to respond to implementing a TOP’s timeframe for which it may not be capable. It is the TOP which should be obligated to be capable of meeting the TOP’s timeframe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1. The SDT put the correlation between R1 and R7 because the TOPs have the direct relationship and communication with the DPs and TOs that they communicate with from a load shed standpoint.	

2. The SDT does not agree that EOP-011 R2 and TOP-002 are redundant. The SDT believes that the process required in TOP-002 R8 is a distinct new process that is intended to address a specific scenario whereas the emergency operating plan is intended to mitigate capacity emergencies during multiple types of scenarios. EOP-011 is a plan to address an emergency that is occurring in real-time. TOP-002 is addressing a look ahead process to avoid needing to implement the EOP Plan in real-time. The SDT does not agree with this statement. The DP does have the obligation of having provisions for manual load shedding capability of being implemented in a timeframe adequate for mitigating the emergency.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
Gas is important for generation but generation is also important. Non-BES connected distributed generation should also be identified that would provide support to the BES.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of the SDT is limited to responding to the FERC recommendations per the SAR.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Please consider updating TOP-002-5 Section C. Compliance with the most recent NERC wording used for the compliance section.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has updated this wording in the posted draft.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments.
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis
Answer
Document Name
Comment
PJM supports the IRC SRC comments.
Likes 0
Dislikes 0
Response
Thank you for your comments. Please see response to IRC SRC.
Kimberly Turco - Constellation - 6
Answer
Document Name
Comment
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segements 5 and 6
Likes 0
Dislikes 0
Response

Thank you for your comments.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to EEI.	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	

Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see response to EEI.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC signed on to ACES comments: We believe the proposed modifications are a good first attempt at meeting the identified key recommendations; however, we also believe that there are a few key areas that need additional review and clarification. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Joshua London - Eversource Energy - 1, Group Name Eversource	

Answer	
Document Name	
Comment	
EOP-011 R1.2.5.5 should be removed and the requirement "Provisions for the identification and prioritization of designated critical natural gas infrastructure loads" be a DP only responsibility(R7.1.5.). TOP's do not know what natural gas customers they serve and where 'critical natural gas infrstructure' loads are found on the distribution system, and sharing of customer information from DP to TOP may not always be allowed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the TOP should have provisions while understanding that the DP may have the relationship with the natural gas supplier. The DP would have to share their load shedding plan, not detailed customer information.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
ReliabilityFirst appreciates the Standard Drafting Team's diligent work on this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	

Answer	
Document Name	
Comment	
Exelon supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	

ATC does not believe that critical natural gas infrasture loads require its own sub-requirement for R1.2.5, since it is a subset of "designated critical loads."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT believes that specifically calling out critical natural gas loads is needed to meet the FERC recommendations.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	

Response
Thank you for your response.