Comment Report

Project Name:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Draft 1
Comment Period Start Date:	5/19/2022
Comment Period End Date:	6/21/2022
Associated Ballots:	2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-011-3 | Non-binding Poll IN 1 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-011-3 IN 1 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 | Non-binding Poll IN 1 NB 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination EOP-012-1 IN 1 ST 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Implementation Plan IN 1 OT

There were 108 sets of responses, including comments from approximately 249 different people from approximately 162 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT revised EOP-011-3 requirements R1 and R2 for the TOP to minimize the overlap of UFLS and UVLS circuits from those used for manual load shed or those that serve critical loads. Should PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 also be modified to include a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's upon request, in order to ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 Requirement R1.2.5.3? Please provide any explanation with your response.

2. Should the BA be the entity to determine the "winter season", which is used to define applicable generating units in proposed EOP-012-1 Section 4.2 Facilities? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. The SDT proposes to include as applicable Facilities in EOP-012-1 only those generating units that operate during the winter weather season, while exempting those units utilized for summer peaking purposes only (and without penalizing such units that may be called upon by the BA during winter weather in response to energy emergencies). Do you agree with the applicability of EOP-012-1 as drafted? If you do not agree, please provide recommended language for how to address from the standard's applicability consistent with the recommendations of The Report.

4. Does the proposed language in EOP-012-1 requirement R1 that require existing units to implement new freeze protection measures or modification of existing freeze protection measures, raise any stakeholder concerns? If so, please provide details of the concern, suggestions to the proposed language that addresses the risk presented in recommendation 1f, and if appropriate, technical or procedural justification.

5. The SDT has proposed that owners of new generation that determine that they are not able to implement freeze protection measures due to technical, commercial, or operational constraints review their determination every five years for EOP-012-1 Requirement R2. Is this separate requirement for "new" generation necessary, given that proposed Requirement R4 provides for Generator Owners to perform a similar review every five years to address the ongoing need to review freeze protection measures and historical cold weather temperatures? Please provide any explanation with your response.

6. The Standard, as proposed, would require Generator Owners to develop plans for modifying generating units to operate to the minimum hourly temperature over the next five years after Commission approval. While Generator Owners identify those generating units that need modifications, develop corrective action plans, and implement modifications, it is important for the ERO Enterprise to have aggregated data about the status of Generation Owners' extreme cold weather preparedness for its generating units for use in its reliability oversight activities.

The SDT believes that there is benefit to having the ERO Enterprise collect information on progress of Generator Owner plans for modifying generating units. The information could be collected through reporting under mandatory Reliability Standard requirements, through a Periodic Data Submittal under Section 400 of the Rules of Procedure (which may or may not be specified in the Compliance section of the standard), or through a request for data under Section 1600 of the Rules of Procedure. Which of these options do you believe is the best procedural option for collecting this information?

7. The drafting team has developed a proposed data collection framework which could form the basis for a periodic data submittal. If you have any comments or edits to the suggested language, please propose an alternative to address the identified risk during the phased-in compliance period.

Collection framework:

- **The Generator Owner will submit an annual summary table by October 1 of each year to its Regional Entity regarding the status of its generating units (as that term is used in EOP-012-1 4.2 Facilities) having freeze protection measures in accordance with Requirements R1 and R2, along with a nine-year projection of status based on the timetables it has determined for Requirement R1. All projections will be based on the Generator Owner's timetables under Requirement R1.4.2; if timetables are not complete for all units, some MW can be designated as "to be determined." The summary table shall contain:**
  - **Status year (for current year, and future years 1-9);**
  - **Sum of capacities (in MW) of all generating units applicable under Facilities, section 4.2;**
  - **Sum of capacities (MW) of generating units meeting (for current year) and projected to meet (for each of the future years 1-9) the criteria of Requirement R1.1;**
  - **Sum of capacities (MW) of generating units not meeting (for current year) and projected to not meet (for each of the future years 1-9) the criteria of Requirement R1.1;**
  - **Sum of the capacities (MW) of existing generating units declared for no action under Requirement R1 (for current year, and projected for future years 1-9);**
  - **Sum of the capacities (MW) of new generating units identified for no action under Requirement R2 (for current year, and projected for future years 1-9).**

9. The SDT is proposing an 18-month implementation time frame for all revised and new requirements except EOP-012-1 Requirements R1 and R2 which have a 5-year implementation time frame. Do you agree with this implementation time frame? 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.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
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
Portland General Electric Co.	Daniel Mason	6		PGE FCD	Ryan Olson	Portland General Electric Co.	5	WECC
					Brooke Jockin	Portland General Electric Co.	1	WECC
					Daniel Mason	Portland General Electric	6	WECC
Elizabeth Davis	Elizabeth Davis		RF,SERC	ISO/RTO Council (IRC) Standards Review Committee (SRC)	Mike Del Viscio	PJM	2	RF
					Becky Davis	PJM	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Helen Lainis	IESO	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Al Miremadi	CAISO	2	WECC
					Dana Showalter	Electric Reliability	2	Texas RE

						Council of Texas, Inc.		
					Kathleen Goodman	ISO-NE	2	NPCC
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
PPL - Louisville Gas and Electric Co.	Jennifer Blair	1,3,5,6	SERC	PPL NERC Registered Affiliates	James Frank	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
					Michelle Longo	PPL Electric Utilities Corporation	1	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Susan Sosbe	Wabash Valley Power Association	3	RF
					Nick Fogleman	Prairie Power, Inc.	1	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Patti Metro	National Rural Electric Cooperative Association	3	NA - Not Applicable
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission	1	MRO

						Company, LLC		
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
LaKenya VanNorman	LaKenya VanNorman		SERC	FMPA and Members	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
					Don Cuevas	Beaches Energy Services	1	SERC

					Carolyn Woodard	Beaches Energy Services	3	SERC
					Aaron Casto	Florida Municipal Power Pool	6	SERC
					Jakub Pajak	Fort Pierce Utilities Authority	3	SERC
					Nick Batty	Keys Energy Services	4	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
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy- FirstEnergy	4	RF
Northern California Power Agency	Marty Hostler	4		NCPA	Michael Whitney	Northern California Power Agency	3	WECC
					Scott Tomashefsky	Northern California Power Agency	4	WECC
					Dennis Sismaet	Northern California Power Agency	6	WECC
					Marty	Northern California Power Agen	5	WECC
Santee Cooper	Marty Watson	5		Santee Cooper	Robert Rhett	Santee Cooper	1,3,5,6	SERC
					Paul Camilletti	Santee Cooper	1,3,5,6	SERC
					Rene' Free	Santee Cooper	1,3,5,6	SERC
					Domenic Ciccolella	Santee Cooper	1,3,5,6	SERC

					Carl Price	Santee Cooper	1,3,5,6	SERC
					Todd Thomas	Santee Cooper	1,3,5,6	SERC
					Ged Moree	Santee Cooper	1,3,5,6	SERC
					Darby Gallagher	Santee Cooper	1,3,5,6	SERC
					William Stevick	Santee Cooper	1,3,5,6	SERC
					Jeffrey Zeigler	Santee Cooper	1,3,5,6	SERC
					Robert Long	Santee Cooper	1,3,5,6	SERC
Public Utility District No. 1 of Chelan County	Meaghan Connell	5		PUD No. 1 of Chelan County	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
					Meaghan Connell	Public Utility District No. 1 Chelan County	5	WECC
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Northern California Power Agency	Michael Whitney	3		NCPA	Scott Tomashefsky	Northern California Power Agency	4	WECC
					Marty Hostler	Northern California Power Agency	5,6	WECC

					Marty Hostler	Northern California Power Agency	5,6	WECC
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
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen	5	NPCC

	Engineered Solutions International Inc.		
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC
Randy MacDonald	NB Power Corporation	2	NPCC
Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
Vijay Puran	NYSPS	6	NPCC
ALAN ADAMSON	New York State Reliability Council	10	NPCC
Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
Brian Robinson	Utility Services	5	NPCC

					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	1		OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					Patrick Wells	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO
Tim Kelley	Tim Kelley		WECC	LPPC	Holly Chaney	Snohomish County PUD No. 1	3	WECC

					Joe McClung	JEA	1	SERC
					Nicole Looney	Sacramento Municipal Utility District	3	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC

					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. The SDT revised EOP-011-3 requirements R1 and R2 for the TOP to minimize the overlap of UFLS and UVLS circuits from those used for manual load shed or those that serve critical loads. Should PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 also be modified to include a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's upon request, in order to ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 Requirement R1.2.5.3? Please provide any explanation with your response.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan

Answer	No
Document Name	

Comment

No. Revisions to PRC-006 and PRC-010 are not necessary. The proposed revisions to EOP-011 are sufficient to address the related recommendation from The Report and obligate the Transmission Operator to have provisions in their Operating Plan to address these requirements. The Transmission Operator must determine how these provisions are handled for entities and load they may represent.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

Avista presently avoids critical loads with its UFLS plan. The Manual Load Shedding is may contain some critical loads. There is extremely wide overlap between the UFLS and Manual Load Shedding. Given the nature of Avista's system, the amount of load available for Manual Load Shedding will be greatly reduced under this standard. I recommend a NO vote with the following comment. "UFLS schemes are designed to address a multiple contingeny resource loss in real-time. They are not designed to be used during an Energy Emergency where there is no sudden frequency change. The UFLS loads are carefully chosen to avoid critical and sensitive loads. In many cases, the UFLS loads are also used for a manual load shed event, which by definition is slower, and not a frequency sensitive event. Manual Load Shedding is not occurring during a sudden frequency excursion. By limiting the overlap of the two load shedding schemes, flexibility of the BA/TOP to manage load resource balance in an EEA is severely compromised, and the amount of Manual Load Shedding available is greatly reduced. This will likely result in the interruption of critical loads during an EEA as the situation deteriorates and the System Operator is left with very limited options during an EEA."

Likes 0	
Dislikes 0	

Response

Israel Perez - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

We do not have UVLS and we believe that PRC-006 and PRC-012 should NOT be modified.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

The IESO is assuming the following:
1. TOP is responsible for establishing and implementating the Operating Plan.
2. TOP orders the maual load shed if and when required.
3. UFLS and UVLS load shedding entities make the arming selections (make the circuits available) for shedding.

The IESO strongly believes that the most effective means to ensure minimization of the overlap of circuits as required by the newly proposed EOP-011-3 is to add the UFLS and UVLS Load Shedding Entities as applicable functional entities. Since UFLS and UVLS load shedding entities are responsible for the arming selections, they are the ones that implement the corrective load shedding circuit requirements.

As such, the IESO requests that UFLS and UVLS load shedding entities be added as applicable functional entities in the newly revised EOP-011-3.

In addition, a new requirement should be added to the newly revised EOP-011-3 that requires the UFLS and UVLS Load Shedding Entities to meet the provisions included in the TOP Operating Plan for operator-controlled manual Load shedding during an Emergency that include:
1. Manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency
2. Minimizing the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads
3. Minimizing the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS
4. Limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Having multiple Requirements with the same intent will introduce risk of double (non-compliance) jeopardy. PRC-010-2 R8 already states that the UVLS database be made available to TPs. Likewise, PCR-006-5 R14 states that the PC shall respond to written comments from applicable entities that want this data.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

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

Answer	No
Document Name	

Comment
DTE Electric supports NAGF comments.

Likes 0	
Dislikes 0	

Response
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	No
Document Name	

Comment
ISO-NE does not support an additional requirement on the Planning Coordinator (PC) to provide data to the Transmission Operator (TOP). The TOP is responsible for providing the PC with the relevant UFLS/UVLS circuit information as currently written. This would only serve to place an additional administrative burden on the PC. The SDT should consider adding the UFLS/UVLS Distribution Providers to the Applicable Facilities for these requirements.

Likes 0	
Dislikes 0	

Response
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	No
Document Name	

Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation observes that coordination and planning information exchange is already covered in other standards. The addition of new requirements to these standards is unnecessary and would likely cause confusion.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
Pacific Gas & Electric (PG&E) supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4, Group Name NCPA	
Answer	No
Document Name	
Comment	

NCPA agrees with the comments of IESO.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report [The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov)] the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	

NCPA agrees with the comments of IESO.

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
UFLS schemes are designed to address a multiple contingeny resource loss in real-time. They are not designed to be used during an Energy Emergency where there is no sudden frequency change. The UFLS loads are carefully chosen to avoid critical and sensitive loads. In many cases, the UFLS loads are also used for a manual load shed event, which by definition is slower, and not a frequency sensitive event. Manual Load Shedding is not occurring during a sudden frequency excursion. By limiting the overlap of the two load shedding schemes, flexibility of the BA/TOP to manage load resource balance in an EEA is severely compromised, and the amount of Manual Load Shedding available is greatly reduced. This will likely result in the interruption of critical loads during an EEA as the situation deteriorates and the System Operator is left with very limited options during an EEA.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP does not see a reliability benefit in requiring that program database data be provided to the Transmission Operator's upon request, and does not recommend revising PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No. Revisions to PRC-006 and PRC-010 are not necessary. The proposed revisions to EOP-011 are sufficient to address the related concerns.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	No
Document Name	
Comment	
No. Revisions to PRC-006 and PRC-010 are not necessary. The proposed revisions to EOP-011 are sufficient to address the related concerns.	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	No
Document Name	
Comment	
AE does not feel strongly that there is a need to modify PRC-006-5 R7 or PRC-010-2 R8. As a TOP, AE is able to comply with the requirements without receiving the UFLS/UVLS program database data from the Planning Coordinator.	

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	No
Document Name	

Comment

The Planning Coordinator's program typically only identifies percentages of load for a given frequency and time "step". The actual specific feeders that are part of a UFLS program of UVLS program are determined by the "UFLS Entities" under the PRC-006 standard / the "UVLS Entites" under PRC-010. The TOP needs to know the specific feeders, and so the UFLS /UVLS entities would be the ones that need to provide that data to the TOP. This information is already shared between UFLS/UVLS Entities as their operations staff today, but not in a formal requirement.

Likes 0	
Dislikes 0	

Response

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	No
Document Name	

Comment

Having multiple Requirements with the same intent introduces confusion and the risk of double jeopardy for non-compliance. Coordination and planning information exchange is already covered in other standards. The addition or change of requirements is unnecessary.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	

Comment

WECC supports this project and all comments provided by WECC are for drafting team consideration in an attempt to provide clarity or improvement. It may not be necessary to modify PRC-006-5, R7, or PRC-010-2, R8, because TOPs should be able to obtain the required data from entities within their footprint via their Data Specification process required in TOP-003. However, if the drafting team believes it may be beneficial for reliability to specifically require this information from the PC, rather than leaving it up to the TOP to include it in their Data Specification process, WECC is not opposed to adding this requirement to the two Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	

Capital Power believes that improvements in industry communication should be facilitated consistently across all regions through a centralized portal (i.e. Align) rather than through the addition of administrative compliance requirements.

Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	

MidAmerican supports MRO NSRF's comments. Having multiple Requirements with the same intent will introduce risk of double (non-compliance) jeopardy. PRC-010-2 R8 already states that the UVLS data base be made available to TPs. Likewise, PCR-006-5 R14 states that the PC shall respond to written comments from applicable entities that want this data.

Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	

PRC-006-5 mandates UFLS entities to "*provide automatic tripping of Load in accordance with the UFLS program design*" as provided by the Planning Coordinator (PC). Therefore, the PC does not necessarily identify specific circuits for load shed action. Further, PRC-010-2 follows the same pattern of PRC-006-5. Typically, the PC communicates to the UFLS/UVLS entities the amount of load shed needed. It is then up to the UFLS/UVLS entity, the Transmission Owner (TO) and/or Distribution Provider (DP), to identify specific circuits for installation of necessary equipment. Of these two functional registrations, it is the DP who has intimate knowledge of the existence of critical loads, such as flood control pumping stations, police and fire dispatch offices, hospitals, etc. The TOP typically does not have the ability to perform manual load shed action which can avoid critical loads. This must be done in the distribution level or in coordination with the DP who is able to identify which transmission circuits can be tripped that will avoid critical load loss. It is better to require the TOP to coordinate a manual load shed plan with the TO and DP within the EOP standards. The TO and DP have the UFLS/UVLS program implementation and critical load data needed to develop a manual load shed plan which would respect the automatic load shed blocks; the PC is not originator of any of the required data. PRC-006 and PRC-010 should not be mixed in with manual load shed planning. Further, developing UFLS and UVLS designated areas where critical loads are not impacted is challenging. Therefore, endeavoring to identify other loads for manual load shed not overlapping UFLS and UVLS may prove to be a compliance burden more devoted to documenting why overlapping is unavoidable.

Likes 0	

Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLS believes that PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 should not be modified to include a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's. As in current practice, UFLS and/or UVLS program database data is coordinated at the Distribution/Transmission level for each applicable entity where loads and assessment of overlap of loads that serve critical loads are identified. This data is then provided to the Planning Coordinator to be implemented as part of the Planning Coordinator's UFLS Program design. The proposed revisions to EOP-011-3 address the recommendations reported and require TOPs to incorporate the new criteria in their deployment and coordination of loads between manual load shed and UFLS/UVLS events.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC does not support the addition of a new administrative requirement on the Planning Coordinator to provide UFLS/UVLS circuit information back to the Transmission Operator but rather mirror the applicability sections of the PRC Standards within the applicability section of EOP-011-3 and requests that EOP-011-3 be modified to ensure the applicable functional entities are identified and responsible for the Load shedding requirements of manual/automatic and UFLS/UVLS circuits. This addition aligns with other NERC Standards where a subset of Distribution Providers and Transmission Owners are responsible for the ownership, operation, or control of the Load shedding circuits (one example is in the applicability section of PRC-010-2 where the functional entities are defined in detail to meet the applicable requirements.) *Proposed language for EOP-011-3* *Applicability:* *Transmission Owners* *Distribution Providers* *UFLS-Only Distribution Providers* *UVLS-Only Distribution Providers*	

R2. *Each applicable Transmission Owner and Distribution Provider responsible for the ownership, operation, or control of manual Load shedding; and UFLS-Only Distribution Providers and UVLS-Only Distribution Providers shall meet the provisions included in the Transmission Operating Plan for operator-controlled manual Load shedding during an Emergency that include:*

R2.1 *Manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;*

R2.2 *Minimizing the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;*

R2.3 *Minimizing the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS*

R2.4 *Limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.*

M2. *Each Transmission Owner and Distribution Provider responsible for the ownership, operation, or control of manual Load shedding; and UFLS-Only Distribution Providers and UVLS-Only Distribution Providers shall provide evidence of meeting its Transmission Operator's Operating Plan(s) regarding provisions for operator-controlled manual Load shedding during an Emergency.*

Per the Extreme Cold Weather Grid Operations, Preparedness, and Coordination SAR Phase 1, the need to include Transmission Owners (TOs) and Distribution Providers (DPs) is listed within the SAR: "4. In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS)/undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency). (Report Key Recommendation 1j)" Manual and automatic load shed entities include applicable TOPS, TOs, and DPs and the addition to the Applicability section of EOP-011-3 is needed to support the expanded TOP Load shed provisions.

In the Joint Inquiry Report, under Section 2d. Preparedness for Emergency Operations; i. Manual and Automatic Load Shed Plans; reports "Distribution Providers (DP) have the responsibility for determining exactly which circuits are to be disconnected during a load shed event." The proposed revisions in EOP-011-3 will require the recognition of designated critical loads and minimizing any overlap of the circuits designated for manual Load shed. This section of the Report also highlights DPs as being required to determine underfrequency relay locations in order to minimize the geographical area of underfrequency events. Having the TO/DP added for UFLS (and UVLS) will ensure the correct circuits are used in minimizing the overlap between manual Load shed and UFLS/UVLS circuits.

Recommendation 10 includes Transmission Owners and Distribution Providers in coordinating Load shed plans. This further justifies the need to include TOs and DPs in EOP-011-3 to require this coordination in both planning and real-time operations.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment

Manitoba Hydro believes that without the loads earmarked for UFLS and UVLS known, and considered in the planning stage, entities may not be able to provide sufficient load shed to weather sudden and long term system events.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
If the new overlap language in the requirements will be retained, then TOPs will need access to this information. However, manual load shed at the transmission level will invariably impact distribution UFLS or UVLS as well as loads deemed critical by some entity. Reliability may be better served by requiring the Distribution Provider to know which distribution loads are critical or involve feeders involved in UFLS or UVLS, and require the Distribution Provider to manually shed load in response to an Operating Instruction from a Transmission Operator or Balancing Authority. When the Transmission Operator has to perform load shed at the transmission level, time is of the essence since there is no time to issue an Operating Instruction and load should be shed in the most efficient manner, which may mean taking some critical load and/or some load also involved in UFLS or UVLS.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
To ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 R1.2.5.3, a review of PRC-006-5 R7 should be performed to minimize the redundancy between the PRC-006-5 and ECOP-011-4 standards.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes

Document Name	
Comment	

In many cases, UFLS and UVLS are implemented on the distribution system, and thus the TOP may not have available detailed information to reflect these in their manual load shedding operations.

Likes 0	
Dislikes 0	
Response	

Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1

Answer	Yes
Document Name	
Comment	

In addition to revising PRC-006 and PRC-010, VELCO requests that the Standard Drafting Team revise EOP-011 with due consideration to areas of the ERO Enterprise for which the Transmission Operator does not serve as a Distribution Provider nor UFLS-Only Distribution Provider. For example, in Vermont, VELCO is a transmission-only TOP registered entity. VELCO serves DP and UFLS-Only DP registered entities, which have operational responsibility for both the sub-transmission and distribution system.

As defined in the Joint Inquiry Report (and is the practice in Vermont), “Load Shed” is “the reduction of electrical system load or demand by interrupting the load flow to major customers and/or **distribution circuits**, normally in response to system or area capacity shortages or voltage control considerations” (emphasis added).

Thus, in the event of an Emergency, VELCO would rely upon DP and UFLS-Only DP entities to (1) implement manual Load shedding in a timeframe adequate for mitigating the Emergency, (2) minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads, (3) 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 (4) limit the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

As written, however, EOP-011 has the unintended consequence of requiring VELCO and other transmission-only entities to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies in Vermont’s Transmission Operator Area. A targeted approach to allow TOPs to identify, as necessary, DP and UFLS-Only DP entities that are required to mitigate operating Emergencies in a TOP’s Transmission Operator Area is therefore warranted. For the SDT’s reference, NERC Standard EOP-005-3 provides an illustrative example of a targeted approach for TOPs to both identify DPs and assign responsibilities to DPs based on need.

Given the reasons stated, VELCO requests the following three (3) modifications to EOP-011:

1. Add Distribution Provider and UFLS-Only Distribution Provider to the applicability section:

a. "**4.1.4.** Distribution Provider identified in the Transmission Operators Operating Plan to mitigate operating Emergencies"

b. "**4.1.5.** UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan to mitigate operating Emergencies"

2. Add Requirement R1.2.5.5., stating:

a. "**R1.2.5.5.** Provisions for identifying Distribution Providers and UFLS-Only Distribution Providers required to mitigate operating Emergencies in its Transmission Operator Area."

3. Add a new Requirement R6, stating:

R6. Each Distribution Provider and UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan(s) as required to mitigate operating Emergencies in its Transmission Operator Area shall implement the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]

6.1. Operator-controlled manual load shedding during an Emergency that accounts for each of the following:

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

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

6.1.3. 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

6.1.4. 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

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	

Comment
This will require periodic updates to ensure that UFLS and UVLS circuit data is accurate.

Likes 0	

Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

IF EOP-011-3 is approved as is, BPA supports revising PRC-006 and PRC-010, and is not opposed to sharing its database data with adjacent TOPs, upon request.

Currently, and as written, BPA does not support the EOP-011-3 revisions. Please see BPA's comments to this posting and, its reiterated SAR comments below.

From BPA's perspective, BPA directs entities to perform Manual Load Shed but it does not prescribe where and how to complete the task. BPA has no voice in how entites determine critical loads. BPA does not have distribution level diagrams for customer load within load centers (Citites, counties, etc.). It's difficult to avoid overlap between Manual Load Shed and those that are armed for UFLS/UVLS. Some overlap is inherent. PRC-006 NWPP Plans require a minimum 34.5% of BPA's load to be armed for BPA's UFLS. To allow for margin, and to maintain compliance, BPA actually has 38-40% armed for UFLS. BPA's Manual Load Shed plan is for 38% of BPA's load. This leads to the amount of breakers that can be opened. There's only so many breakers that meet the requirements to be used in load shed.

BPA's comments submitted to the SAR (Dec. 2021)

BPA's UFLS plans avoid Natural Gas and other critical loads. If BPA issues a Manual Load Shed directive, it is up to the recipient of that directive to make an informed decision regarding which loads to shed within their distribution area. BPA prescribes a certain amount of MW load, within a certain amount of time, in the Manual Load Shed plan. Then, the recipient of the directive (Public Utility, etc.) decides which loads to shed. In order for BPA to meet the minimum requirements, for both Manual and Automatic Load Shed, it would equate to roughly ¾ of the load in BPA's Balancing Authority Area. BPA believes it is not practical or feasible to completely minimize overlap between the Manual and Automatic Load Shed plans. BPA disagrees with the report's recommendation pertaining to this issue, thus, does not recommend modifying any current Reliability Standards (PRC-006, PRC-010, etc.) at this time.

Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	

This will require periodic updates to ensure that UFLS and UVLS circuit data is accurate.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Dominion Energy supports the EEI comments and agrees that for Transmission Operators to ensure they are meeting the intent of EOP-011, Requirement R1 subparts 1.2.5.2, 1.2.5.3 and 1.2.5.4, they will need the same database lists that are provided by the UFLS and UVLS entities to the responsible Planning Coordinator. To ensure this is done and the required information is shared, PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 should be modified to include sharing with the affected Transmission Operator. Additionally, this information/database should be circulated/shared whenever the PC receives an updated version, not just upon request by the TOP.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

All TOPs may not have the information needed to ‘minimize the overlap of circuits’. Planning Coordinators gather the UFLS and UVLS data as part of their program design, so this modification to the Standards would ensure TOPs would be provided this information upon request

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	

Comment

we support the RSC comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	

Comment

YES, by not requiring the option of the data to be shared, there is a good chance, a feeder could be used in both plans.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3	
Answer	Yes
Document Name	

Comment

WEC Energy Group supports EEIs comments.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Texas RE agrees there should be a Requirement that Planning Coordinators shall provide UFLS and/or UVLS (as applicable) program database data to Transmission Operator's upon request, in order to ensure that all TOPs have the necessary data to minimize the overlap of circuits as required in the newly proposed EOP-011-3 Requirement R1.2.5.3. The System Operators will be more prepared with more information.

Texas RE recommends capitalizing "load" in 1.2.5 as it is a defined term in the NERC Glossary.

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

AEPCO signed on to ACES comments below:

We support a review of PRC-006-5 R7 and PRC-010-2 R8 standards during the next logical review cycle of those Standards but do not believe the suggested modifications is a high priority. We understand the importance of providing clarity on managing the data collection requirements associated with UFLS and UVLS programs.

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

Document Name	
Comment	
Southern Company supports the EEI comments and would add language to the end of PRC-006-5 R7 and PRC-010-2 R8 stating, "… and to the affected Transmission Operators within 90 days of receiving an updated version of the database."	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
NAGF Comments: Industry communication should be improved. To the extent that a registered entity needs information from another entity or part of their own entity, that information should be provided. This type of communication should not need a requirement to address communications between the two entities.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
AZPS supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
For Transmission Operators to ensure they are meeting the intent of EOP-011, Requirement R1 subparts 1.2.5.2, 1.2.5.3 and 1.2.5.4, they will need the same database lists that are provided by the UFLS and UVLS entities to the responsible Planning Coordinator. To ensure this is done and the required information is shared, PRC-006-5 Requirement R7 and PRC-010-2 Requirement R8 should be modified to include sharing with the affected Transmission Operator. Additionally, this information/database should be circulated/shared whenever the PC receives an updated version, not just upon request by the TOP.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Does not apply to us as GO/GOP. Selected because N/A was not an option.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	
This will minimize the overlap of circuits. This is a current business practice within our entity to avoid any overlap with the manual load shedding plan.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes

Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports the comments of the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports aligning revised EOP-011-3 with existing PRC-006-5 R7 and PRC-010-2 R8.	
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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	

In addition to revising PRC-006 and PRC-010, RSC requests that the Standard Drafting Team revise EOP-011 with due consideration to areas of the ERO Enterprise for which the Transmission Operator does not serve as a Distribution Provider nor UFLS-Only Distribution Provider. For example, in NPCC, there are transmission-only TOP registered entities. These TOPs serve DP and UFLS-Only DP registered entities, which have operational responsibility for both the sub-transmission and distribution system.

As defined in the Joint Inquiry Report (and is the practice in some parts of NPCC), “Load Shed” is “the reduction of electrical system load or demand by interrupting the load flow to major customers and/or **distribution circuits**, normally in response to system or area capacity shortages or voltage control considerations” (emphasis added).

Thus, in the event of an Emergency, transmission-only TOPs would rely upon DP and UFLS-Only DP entities to (1) implement manual Load shedding in a timeframe adequate for mitigating the Emergency, (2) minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads, (3) 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 (4) limit the utilization of UFLS or UVLS circuits for manual Load shed to situations were warranted by system conditions.

As written, however, EOP-011 has the unintended consequence of requiring transmission-only TOPs to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies. A targeted approach to allow TOPs to identify, as necessary, DP and UFLS-Only DP entities that are required to mitigate operating Emergencies in a TOP’s Transmission Operator Area is therefore warranted. For the SDT’s reference, NERC Standard EOP-005-3 provides an illustrative example of a targeted approach for TOPs to both identify DPs and assign responsibilities to DPs based on need.

Given the reasons stated, RSC requests the following three (3) modifications to EOP-011:

{C}1. Add Distribution Provider and UFLS-Only Distribution Provider to the applicability section:

{C}a. “**4.1.4.** Distribution Provider identified in the Transmission Operators Operating Plan to mitigate operating Emergencies”

{C}b. “**4.1.5.** UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan to mitigate operating Emergencies”

{C}2. Add Requirement R1.2.5.5., stating:

{C}a. “**R1.2.5.5.** Provisions for identifying Distribution Providers and UFLS-Only Distribution Providers required to mitigate operating Emergencies in its Transmission Operator Area.”

{C}3. Add a new Requirement R6, stating:

R6. Each Distribution Provider and UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan(s) as required to mitigate operating Emergencies in its Transmission Operator Area shall implement the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]

{C}**6.1.** Operator-controlled manual load shedding during an Emergency that accounts for each of the following:

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

{C}**6.1.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

{C}**6.1.3.** {C}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

Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations were warranted by system conditions.

Additional information is required for a better assessment:

add clarification regarding overlap – physical versus frequency domain action overlap

Additional clarification is required regarding when manual load shedding is permitted for the load connected to a feeder part of the UFLS program (extra load margin required with respect to the minimum amount of load accounted for in the UFLS program)

Manual load shedding shall only be allowed to disconnect the critical load for a period of time that is less than the critical load outage withstand time, without having a negative impact.

Similar to the UFLS program it is the time to have a dynamic approach to the critical loads; they should be treated differently based on the assigned priority and the specifics of the load shedding event in terms of extent, duration, and weather condition/season.

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5

Answer	Yes
Document Name	

Comment

OPC supports ACES comments: We support a review of PRC-006-5 R7 and PRC-010-2 R8 standards during the next logical review cycle of those Standards but do not believe the suggested modifications is a high priority. We understand the importance of providing clarity on managing the data collection requirements associated with UFLS and UVLS programs.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI. Submitted on behalf of Exelon (Segments 1 & 3)	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
We support a review of PRC-006-5 R7 and PRC-010-2 R8 standards during the next logical review cycle of those Standards but do not believe the suggested modifications is a high priority. We understand the importance of providing clarity on managing the data collection requirements associated with UFLS and UVLS programs.	
Likes 0	
Dislikes 0	

Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)	
Likes 0	
Dislikes 0	
Response	
Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
PPL NERC Registered Affiliates support EEI comments on Question 1.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The TOP will need the data from UFLS and UVLS applications to determine if overlap exists with manual load shed expectations. This data will also identify if any additional MWs can be shed manually at these locations once the automatic process has been completed.	
Likes 0	
Dislikes 0	
Response	

Hillary Dobson - Colorado Springs Utilities - 3	
Answer	Yes
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

Additionally, we request that Distribution Provider (DP) and UFLS-Only Distribution Provider be added to the applicability section of EOP-011-3 as well as making the followng addtions to the Requirements:

Add Requirement **R1.2.5.5**. as follows:
R1.2.5.5. Provisions for identifying Distribution Providers and UFLS-Only Distribution Providers required to mitigate operating Emergencies in its Transmission Operator Area."

Add a new Requirement **R6**, as follows:
R6. Each Distribution Provider and UFLS-Only Distribution Provider identified in the Transmission Operators Operating Plan(s) as required to mitigate operating Emergencies in its Transmission Operator Area shall implement the following, as applicable:

6.1. Operator-controlled manual load shedding during an Emergency that accounts for each of the following:
6.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
6.1.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;
6.1.3. 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 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	

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

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	

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Vinson - American Clean Power Association - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
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	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
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	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	

Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	
Comment	
Tenaska is a generator owner and has no comment on this standard.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
N/A – Invenergy is not a Transmission Operator and has no comment on these proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	

Answer	
Document Name	

Comment

Constellation has no comments

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	
Document Name	
Comment	
TCPA is an organization with generators as members so we have no input on this question.	
Likes 0	
Dislikes 0	
Response	
Jun Hua - Austin Energy - 4	

Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
No comment, as Calpine Corporationis a Generation Owner and/or Operator.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
Q1. ERCOT supports the SRC comments and the addition of the proposed language to expand applicability and to establish a new requirement for applicable TOs, DPs, and DPs with UVLS and UFLS circuits. As the SRC noted, the FERC/NERC Report on the February 2021 Cold Weather Outages under Section II.C.2.d, Manual and Automatic Load Shed Plans, states: “Transmission Service Providers and Distribution Providers (DP) have the responsibility for determining exactly which circuits are to be disconnected during a load shed event.” Additionally, in Recommendation 10, the FERC/NERC Report highlights the importance of coordination between Transmission Owners with Distribution Providers in coordinating Load shed plans. There is limited value added by placing the responsibility on the PC within this standard. If the provision of the database to others is determined to be necessary, the requirement should be included within the PRC standard.	
Likes 0	
Dislikes 0	
Response	

Ashley Scheelar - TransAlta Corporation - 5	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	

2. Should the BA be the entity to determine the "winter season", which is used to define applicable generating units in proposed EOP-012-1 Section 4.2 Facilities? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Ashley Scheelar - TransAlta Corporation - 5	
Answer	No
Document Name	
Comment	
Thank you for the opportunity to present our position regarding these proposed standards. A consistent theme that is presented in our responses is that many generators in the North, particularly Canada, successfully operate in extreme cold year after year. In addition, many generators operate in regions that do not have the type of reliability risk being addressed by this standard. Therefore, there should be no need for a definition of "winter season" for all regions of North America. However, if an entity is required to define it, TransAlta agrees with the comments provided by NRG Energy.	
Likes 0	
Dislikes 0	
Response	

John Babik - JEA - 5	
Answer	No
Document Name	
Comment	
We Support LPPC's Comments	
Likes 0	
Dislikes 0	
Response	

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	No
Document Name	
Comment	
SNPD supports comments submitted by LPPC and Tacoma Power	
Likes 0	
Dislikes 0	

Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Q2. ERCOT supports the SRC proposed language that proposes a default winter period, but agrees that BA discretion to identify a different definition of winter is appropriate.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC proposes the following language change: The winter season is defined as December through February unless the applicable Balancing Authority decides otherwise.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
The burden should be on the GO to identify the “winter season,” or better, the yearly time span of heightened cold weather risk to the affected Balancing Authority (BA) entities. Further, the GOP can communicate real time heightened risk to the affected BAs to allow for contingency planning. As far as defining applicable generating units in proposed EOP-012-1 Section 4.2 Facilities, it is better to first assume all BES generation is applicable, then define a list of exclusions. Certain generation units are highly unlikely to be directly impacted by cold weather and can demonstrate this via historical	

data extending back 60 years. Reliability efforts should not be incumbered with compliance and monitoring activity with little to no return in benefit to BES stability.	
Likes 0	
Dislikes 0	
Response	
Hillary Dobson - Colorado Springs Utilities - 3	
Answer	No
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
We request that the SDT provide justification for selecting the BA as the entity rather than the RC. In addition, whichever entity is ultimately selected, we feel it would be beneficial to include this determination as it's own requirement rather than leaving it in the Facilities definition section. In taking this approach, the entity would be identified as an "Applicable Entity" in section 4.1 Functional Entities of the standard.	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	

CHPD agrees with LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	
Comment	
OPC supports ACES comments: We request that the SDT provide justification for selecting the BA as the entity rather than the RC. In addition, whichever entity is ultimately selected, BA of RC, we feel it would be beneficial to include either this determination as it's own requirement rather than leaving it in the Facilities definition section. In taking this approach, the entity would be identified as an "Applicable Entity" in the standard.	
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 Regional Standards Committee	
Answer	No
Document Name	
Comment	
How is the BA held responsible for determining what is considered the "winter season"? EOP-012-1 section 4.2 lacks clarity and there are no requirements concerning this responsibility, nor is it mentioned in the TR. Local BA to provide the "winter season" It is not the winter season that determines the applicability to Facilities (generating units), but rather the potential for localized extreme weather conditions.	
Likes 0	
Dislikes 0	
Response	

Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Captial Power believes that focus should be on operation capability during certain weather / temperatureconditions rather than arbitrarily chosen seasons. Capital Power supports the NAGF revisions which eliminate the need for the definition of this term.	
Likes 0	
Dislikes 0	
Response	

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Determining the winter season should be applicable to GOs. GO actions within the requirements should have deadlines set by the GO. The BA could be located in a different weather zone than the GO's Facilities and therefore not familiar enough with the details to choose a date range that matches local conditions. The BA is not listed under Applicability/Functional Entity.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Section 4.2 - Facilities states "The winter season will be determined by the generating unit's applicable Balancing Authority." Duke Energy suggest this sentence be removed. Additionally, per the NAGF, "there is not a requirement that addresses anything being done during the winter period. All requirements address cold weather issues. For this reason, it is recommended that this sentence be struck from the applicability." If the current language is not removed: (a) Balancing Authorities (BA) as a Function Entity should be added to Section 4.1 – Functional Entities to ensure BA's have a compliance obligation to provide "winter season" information to generating unit's , and	

(b) The SDT should add appropriate BA submittal language to a new or existing Requirement to ensure the action is enforceable and “winter season” information is submitted by the BA.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	No
Document Name	
Comment	
As proposed, EOP-012-1 does not include the BA as an applicable functional entity. IID recommends that if the BA is required to perform a regulatory required function, such as defining “winter season”, then the BA should be listed as a responsible functional entity in the Applicability section, along with the GO and GOP. Additionally, a Requirement should be included in EOP-012-1 that specifies the BA’s responsibility of working with the GO and GOP to define “winter season” and identify units that will or will not be available for that season. The BA needs input from the GOP and GO to understand the temperature and seasonal limitations for each unit to define the “winter season” and which units are summer peaking only. In addition, further guidance is needed on the exclusion of generators but which could be called upon by the BA (specifically since the BA is not listed as a functional entity).	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
Answer	No
Document Name	
Comment	
Colorado Springs Utilities agrees with comments endorsed by LPPC	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	

Answer	No
Document Name	
Comment	

Constellation Energy Generation (CEG) does not agree the BA should be the authority on determining cold weather, rather the GO/GOP is in the best position to make the determination of defining the winter season based on regional climate differences. Also, the BA is not included in the standard as an applicable entity and therefore should not have the ability to make this determination. Constellation suggests also that "winter season" should not be defined in the standard based on these regional variances. The current title of the draft EOP-012 is "Extreme Cold Weather", not "Winter". Removing the limitation of a defined "winter" season helps ensure generator availability for any cold weather period.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

Agree with NAGF comments

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	
Comment	

Constellation Energy Generation (CEG) does not agree the BA should be the authority on determining cold weather, rather the GO/GOP is in the best position to make the determination of defining the winter season based on regional climate differences. Also, the BA is not included in the standard as an applicable entity and therefore should not have the ability to make this determination. Constellation suggests also that "winter season" should not be defined in the standard based on these regional variances. The current title of the draft EOP-012 is "Extreme Cold Weather", not "Winter". Removing the limitation of a defined "winter" season helps ensure generator availability for any cold weather period.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	No
Document Name	
Comment	
As proposed, EOP-012-1 does not include the BA as an applicable functional entity. LPPC recommends that if the BA is required to perform a regulatory required function, like defining “winter season”, then the BA should be listed as a responsible Functional Entity in the Applicability section, along with the GO and GOP. Additionally, a Requirement should be included in EOP-012-1 that specifies the BA’s responsibility of working with the GO and GOP to define “winter season” and identify units that will or will not be available for that season. The BA needs input from the GO and GOP to understand the temperature and seasonal limitations for each unit to define the “winter season” and which units are summer peaking only. These comments have been endorsed by LPPC.	
Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	
NAGF Comments: The NAGF believes there is no need to define the winter season. The NAGF proposed revisions to EOP-012-1 eliminate the need for such a definition.	
Likes 1	Greybeard Compliance Services, LLC, 5, Gabriel Michael
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
This should be left up to the entity, there is no good one size fits all solution here. We believe that the GO or GOP could be responsible for this notification, in addition to notifications of projected cold weather events that could be handled by the GO and GOP for some entities.	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
NCPA agrees with the comments of Tri-State G and T Association, Inc.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.	

On page 86 of FERC/NERC's joint Report [The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov)] the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPCO signed on to ACES comments below:

We request that the SDT provide justification for selecting the BA as the entity rather than the RC. In addition, whichever entity is ultimately selected, we feel it would be beneficial to include this determination as it’s own requirement rather than leaving it in the Facilities definition section. In taking this approach, the entity would be identified as an “Applicable Entity” in section 4.1 Functional Entities of the standard.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	No
Document Name	

Comment

NCPA agrees with the comments of Tri-State G and T Association, Inc.

Likes 0	
Dislikes 0	

Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E recommends that the individual GO's and GOP's determine their own respective "winter seasons". The BA may not have the capability and resources to determine unique winter season dates across a large and diverse region. For example, in California, PG&E has cold weather in the Sierra foothills and at the same time, we have very moderate temperatures at our facilities located on the Pacific Ocean or the Central Valley for the "winter seasons".	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Recommend RC to be the entity to determine the “winter season” to minimize potential for different winter seasons defined by multiple BAs for a single registered entity.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation observes that different definitions of the same term are likely to cause confusion, especially in areas where a single entity has facilities under the jurisdiction of multiple BAs. Reclamation recommends instead of defining “winter season” as a time period, the standard should direct entities	

to begin cold weather preparations when temperatures decrease toward 40 degrees and to implement preparations as temperatures decrease toward 30 degrees. Alternatively, Reclamation recommends a universal “winter season” be defined as October through April.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

we support the RSC comments. Additionally,

How is the BA held responsible for determining what is considered the “winter season”? EOP-012-1 section 4.2 lacks clarity and there are no requirements concerning this responsibility, nor is it mentioned in the TR.

Local BA to provide the “winter season”. It is not the winter season that determines the applicability to Facilities (generating units), rather the potential for localized extreme weather condition.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment	
If it is deceided that a requirement to declare a 'winter season' becomes applicable to BAs, BPA believes it's more clear for BAs base the 'winter season' on a date range (such as October-April).	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
BA's can have a large geographical footprint making it inappropriate to establish a winter season criteria, which varies by site. An additional complication is some generating stations have multiple BA's. The GO or its TOP should be the one to determine the winter seasons. If the SDT elects to utilize the TOP, the TOP should establish a "winter season" on a Facility by Facility basis, much like they do with Voltage Schedules for VAR-001. If the SDT elects to have the GO establish its own "winter season" there should be a requirement regarding the establishment of that season, and the justification for when it occurs.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
As written, EOP-012-1 does not include BA as an applicable functional entity. SRP recommends that if the BA is required to perform a regulatory required function, like defining "winter season", then the BA should be listed as a responsible functional entity in the Applicability section, along with the GO and GOP. Consider including a requirement in EOP-012-1 that specifies the BA's responsibility of working with the GO and GOP to define "winter season" and identify units that will or will not be available for that season. The BA needs input from the GOP and GO to understand the temperature and seasonal limitations for each unit to define the "winter season" and which units are summer peaking only.	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
As proposed, EOP-012-1 does not include the BA as an applicable functional entity. Tacoma Power recommends that if the BA is required to perform a regulatory required function, like defining “winter season”, then the BA should be listed as a responsible functional entity in the Applicability section, along with the GO and GOP. Additionally, a Requirement should be included in EOP-012-1 that specifies the BA’s responsibility of working with the GO and GOP to define “winter season” and identify units that will or will not be available for that season. The BA needs input from the GOP and GO to understand the temperature and seasonal limitations for each unit to define the “winter season” and which units are summer peaking only.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
This should be left up to the entity, there is no good one size fits all solution here. We believe that the GO or GOP could be responsible for this notification, in addition to notifications of projected cold weather events could be handled by the GO and GOP for some entities.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	

We don't think the BA should be held responsible for determining what is considered the “winter season”. EOP-012-1 section 4.2 lacks clarity and there are no requirements concerning this responsibility, nor is it mentioned in the TR!

Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The Reliability Coordinator should make this determination for consistency across the RC footprint.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
If there is a requirement for defining the winter season, LCRA agrees the BA is the best entity that can define this for their respective region.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
If there is a requirement for defining the winter season, LCRA agrees the BA is the best entity that can define this for their respective region.	

Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	TAPS proposed language Q2.docx
Comment	

BA Requirement to determine and communicate definition of winter season
The BA is the appropriate entity to determine the "winter season" for purposes of defining applicable generating units in proposed EOP-012-1. Because applicability of EOP-012 hinges on the BA's determination, the SDT should consider a Requirement, possibly in EOP-011, for the BA to make the determination and communicate it to the GOs in its footprint. Proposed requirement language: "The Balancing Authority shall determine the winter season for its footprint, and shall inform each GO in its footprint of its determination, by [date] of each year for the winter season commencing in that calendar year."

Communication of plan to operate
In addition, to avoid the potential for disagreements over what constitutes a "plan" to operate, EOP-012-1 Section 4.2 could be revised to include communication of the GO's plan to its BA.

Proposed language is attached in redline and clean format.

Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	

The BA is in the best position to determine the "winter season" as they have the first hand knowledge of their planning area and the visibility of entire system as a whole. This also ensures consistency throughout the region.

Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	

Answer	Yes
Document Name	
Comment	

Yes, the BA (or the agency with regulatory oversite of the Balancing Authority) should be the entity to determine the "winter season." This approach accounts for variability in temperature as relates to geographical location. For example, in the Texas RE region, the BA defines the "winter season" as December through February , excluding March, as March is usually a month that experiences milder temperatures in that region. Additionally, the BA (or equivalent entity) is most well-suited to account for climate variability within the sub-regions of the BA itself. Additionally, Calpine proposes that stakeholder input should be allowed and considered in determining the "winter season."

Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	
Comment	

PPL NERC Registered Affiliates support EEI comments on Question 2.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	Yes
Document Name	
Comment	

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	
Comment	

Southern Indiana Gas & Electric Company (SIGE) supports EEI's comment. SIGE supports the BA as the entity to determine the "winter season"; however, EOP-012 does not specifically set a requirement for the BA to define the winter season. The SDT should consider adding the BA requirement to either the Standard language or the Applicability section.

Additionally, in some BA regions the area may be very large, and the BA may need to define winter seasons differently across the area. To address this concern, language should be added to a requirement that obligates the BA to both define the "winter season" and to work with their respective GOs and GOPs to ensure the "winter season" is appropriately defined throughout their area of responsibility.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	
Comment	

MidAmerican supports EEI comments. MidAmerican supports the BA as the entity to determine the "winter season", however, EOP-012 does not specifically set a requirement for the BA to define the winter season. In EOP-012, the Applicability Section is the only place where this is mentioned. Additionally, in some BA regions the area may be very large, and the BA may need to define winter seasons differently across the area. To address this concern, language should be added to a requirement that obligates the BA to both define the "winter season" and to work with their respective GOs and GOPs to ensure the "winter season" is appropriately defined throughout their area of responsibility.

Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	
It should either be the BA or the agency with regulatory oversite of the Balancing Authority. Within a large BA, there may be wide variability in temperature gradients across the BA's footprint and that variability should be accounted for. Regardless, stakeholder input should be allowed in determining the winter season.	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	
The BAs are best positioned to determine their winter season based on region-specific characteristics, their own analysis, and their own stakeholder input.	

Likes 0	
Dislikes 0	
Response	
Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	
Answer	Yes
Document Name	
Comment	
We support LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
TMLP echoes the comments submitted by TAPS Group: **BA Requirement to determine and communicate definition of winter season**	

The BA is the appropriate entity to determine the “winter season” for purposes of defining applicable generating units in proposed EOP-012-1. Because applicability of EOP-012 hinges on the BA’s determination, the SDT should consider a Requirement, possibly in EOP-011, for the BA to make the determination and communicate it to the GOs in its footprint. Proposed requirement language: “The Balancing Authority shall determine the winter season for its footprint, and shall inform each GO in its footprint of its determination, by [date] of each year for the winter season commencing in that calendar year.”

Communication of plan to operate

In addition, to avoid the potential for disagreements over what constitutes a “plan” to operate, EOP-012-1 Section 4.2 could be revised to include communication of the GO’s plan to its BA.

Proposed language (clean)

For purposes of this standard, the term “generating unit” means each Bulk Electric System generator that has informed its Balancing Authority that it plans to operate during the upcoming winter season that has been determined by the generating unit’s applicable Balancing Authority pursuant to EOP-011-3 Requirement R***. The term excludes those generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	Yes
Document Name	

Comment

We support the comments of EEI; it is appropriate that the BA determines the "winter season"

Likes 0	
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	Yes
Document Name	

Comment

I agree with TAPs comments, pasted below:

BA Requirement to determine and communicate definition of winter season

The BA is the appropriate entity to determine the “winter season” for purposes of defining applicable generating units in proposed EOP-012-1. Because applicability of EOP-012 hinges on the BA’s determination, the SDT should consider a Requirement, possibly in EOP-011, for the BA to make the determination and communicate it to the GOs in its footprint. Proposed requirement language: “The Balancing Authority shall determine the winter season for its footprint, and shall inform each GO in its footprint of its determination, by [date] of each year for the winter season commencing in that calendar year.”

Communication of plan to operate

In addition, to avoid the potential for disagreements over what constitutes a “plan” to operate, EOP-012-1 Section 4.2 could be revised to include communication of the GO’s plan to its BA.

Proposed language (clean)

For purposes of this standard, the term “generating unit” means each Bulk Electric System generator that has informed its Balancing Authority that it plans to operate during the upcoming winter season that has been determined by the generating unit’s applicable Balancing Authority pursuant to EOP-011-3 Requirement R***. The term excludes those generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies.

Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	Yes
Document Name	

Comment

Irrelevant who determines "winter season". Practical outcome is that generating facilities need to prepare no matter who selects the "winter season." Selected because N/A was not an option.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	Yes
Document Name	

Comment

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Entergy agrees but would like clarity on consistency of the winter season from year to year and north vs south.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
The SDT appropriately proposes for the applicable Balancing Authority (BA) to define "winter season." This approach recognizes the impact of geographical location on the timing of the winter season. For example, in the Texas Reliability Entity, Inc. (Texas RE) region, the BA (the Electric Reliability Council of Texas, Inc. (ERCOT)) defines "winter season" as December through February, rather than including any portion of March, which typically has milder temperatures in Texas.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the BA as the entity to determine the “winter season”, however, EOP-012 does not specifically set a requirement for the BA to define the winter season. In EOP-012, the Applicability Section is the only place where this is mentioned. Additionally, in some BA regions the area may be very large, and the BA may need to define winter seasons differently across the area. To address this concern, language should be added to a requirement that obligates the BA to both define the “winter season” and to work with their respective GOs and GOPs to ensure the “winter season” is appropriately defined throughout their area of responsibility.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
AZPS supports EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Tom Vinson - American Clean Power Association - 5	
Answer	Yes
Document Name	
Comment	
ACP supports the BA determining the winter season. It makes sense to determine the winter season in a way that accounts for regional/geographic differences in weather. And, having the BA determine the winter season rather than individual generator owners will provide uniformity in approach for a given area, which is helpful in ensuring generators are subject to the same requirements.	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	Yes
Document Name	

Comment	
AE recommends adding the BA as a functional entity under the applicability section and have the requirement of defining the winter season clearly stated as a responsibility of BA with input from GO & GOP.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	Yes
Document Name	
Comment	
The Standard as currently drafted does not require the BA to determine the winter season. There should be a requirement the BA define and coordinate the seasons with the GOs in its footprint. Add something like: "BA shall determine the winter season for its footprint and shall inform each GO in its footprint of its determination, by x-date of each year for the ahead winter season."	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees that the BA is the appropriate entity to determine the winter season. Invenergy suggests that the BA be added as an applicable functional entity in EOP-012-1, and that a separate Requirement be added, which details the method(s) by which the BA will notify subject Generator Owners of their determination.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes

Document Name	
Comment	
Invenergy agrees that the BA is the appropriate entity to determine the winter season. Invenergy suggests that the BA be added as an applicable functional entity in EOP-012-1, and that a separate Requirement be added, which details the method(s) by which the BA will notify subject Generator Owners of their determination.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	Yes
Document Name	
Comment	
The Standard as currently drafted does not require the BA to determine the winter season. There should be a requirement the BA define and coordinate the seasons with the GOs in its footprint. Add something like: “BA shall determine the winter season for its footprint and shall inform each GO in its footprint of its determination, by x-date of each year for the ahead winter season.”	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes

Document Name	
Comment	
AEP supports the BA being the entity to determine the "winter season" in their region. However, in some BA regions the area may be very large, and the BA may need to define winter seasons differently in certain parts of their footprint. To address this concern, we suggest language be added to require the BA to work with their respective GOs and GOPs to ensure the "winter season" is appropriately defined throughout their area of responsibility.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the EEI comments and supports the BA as the entity to determine the "winter season" so long as this determination is applied only to exempt summer peaking generators from the requirements of EOP-12-1 but does NOT determine the timing of when a generating plant should implement its Cold Weather Preparedness Plan each year.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees the BA is the appropriate entity to determine the "winter season". Texas RE recommends the BA coordinate with its RC and the PA/PC so the RC and PA/PC understand when the winter season is determined.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	

Answer	Yes
Document Name	

Comment

WEC Energy Group supports EEIs comments.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

BAs should also be obligated to inform GO/GOPs of their defined “winter season”.

The BA is the appropriate entity to determine the “winter season” for purposes of defining applicable generating units in proposed EOP-012-1. Because applicability of EOP-012 hinges on the BA’s determination, the SDT should consider a Requirement, possibly in EOP-011, for the BA to make the determination and communicate it to the GOs in its footprint. Proposed requirement language: “The Balancing Authority shall determine the winter season for its footprint, and shall inform each GO in its footprint of its determination, by [date] of each year for the winter season commencing in that calendar year.”

Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports the EEI comments that the BA is the entity to determine the “winter season.” However, in some BA regions the area may be very large, and the BA may need to define winter seasons differently in certain parts of their area. To address this concern, we suggest language be added to require the BA to work with their respective GOs and GOPs to ensure the “winter season” is appropriately defined throughout their area of responsibility.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
If there is a requirement for defining the winter season, NRG agrees the BA is the best entity that can define this for their respective region. However, it must be understood that within a large BA, there may be wide variability in temperature gradients across the BA’s footprint and that variability should be accounted for.	
Likes 0	

Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The Balancing Authority (BA) is the best entity to determine what their "winter season" is. The MRO NSRF recommends the SDT review NERC Reliability Standards to verify if a requirement(s) exists for the BA to actually determine a "winter season".	
Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We find the criterion for freeze protection measures is clear (i.e., "capable of continuous operations at the documented minimum hourly temperature experienced at location since 1/1/1975…") and it is just about determining the generating units it applies to, as long as the dates for the winter season are clear, and that it starts before the first freeze and ends after the last.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
If there is a requirement for defining the winter season, NRG agrees the BA is the best entity that can define this for their respective region. However, it must be understood that within a large BA, there may be wide variability in temperature gradients across the BA's footprint and that variability should be accounted for.	

Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
The Standard does not currently require the BA to determine the winter season. A new requirement should be added to ensure the BA provides the seasons to the GOs in its footprint. Suggested language for the Requirement: "The Balancing Authority shall determine the winter season for its footprint and shall inform each GO in its footprint of its determination, by [date] of each year for the ahead winter season commencing in that calendar year."	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Yes, but the SDT should consider that the utilities in a BA need to have the changeover between Summer to Winter limits coordintated, where a BA extends into differening climates, this presents a problem. For example, Lousiana Power's summertime may begin earlier than Manitoba Hydro's summer limits conditions. This may be less of an issue when Dynamic limits come into effect in a few years.	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	

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	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jun Hua - Austin Energy - 4	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

WECC is not opposed to this but offers the following options. The terminology for winter season is widely used for Facility Ratings, System Operating Limits, and Planning purposes. To avoid possible confusion, some consideration might be given to allowing the PC or RC to make this determination. This could allow for consistent terminology between cold weather operations and planning activities. Another consideration is whether it is appropriate to allow a Generator Only BA to establish the winter season for the benefit of its own generation (see suggested language in response to question 3). Another alternative or additional language might include a requirement that the BA determine and identify the “winter season” criteria, make formal declarations of the seasonal status, and communicate those to the GO/GOP.

Likes 0	
Dislikes 0	

Response

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	
Document Name	

Comment

ISO-NE agrees with the SRC comment and suggested language:

The winter season is defined as a minimum of December through February unless the applicable Balancing Authority decide otherwise.

Likes 0	
Dislikes 0	

Response

Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	
Comment	
Regardless of official entity that makes the determination, stakeholder input should be considered.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	

3. The SDT proposes to include as applicable Facilities in EOP-012-1 only those generating units that operate during the winter weather season, while exempting those units utilized for summer peaking purposes only (and without penalizing such units that may be called upon by the BA during winter weather in response to energy emergencies). Do you agree with the applicability of EOP-012-1 as drafted? If you do not agree, please provide recommended language for how to address from the standard's applicability consistent with the recommendations of The Report.

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Capacity emergencies occur in a variety of seasons. This exemption for peaking units will continue the trend of units not being weatherized and fall short of the overall goal, which is to prevent a repeat of the February, 2021 severe winter storm events in Texas. Listing specific criteria for the exemptions in the standard is preferred.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
With the changing generation mix on the electric grid and projected capacity and energy shortfalls by various reliability entities, no BES unit should be exempt from EOP-012 since all may be called on in an extreme cold weather event when other units are unable to start or operate.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

We believe that it is more appropriate to have the meaning of “generating unit” or the exclusion of those generators that do not operate during the winter season, except for as called upon by the BA, in the standard requirement rather than in the Applicability.	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	No
Document Name	
Comment	
VELCO requests that the SDT consider Emergencies in the summer weather season that may warrant protections.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
If there is any chance of the plant operating during any cold weather energy emergency then the standard should apply. Some of the primary issues in past cold weather events have been tied to units that were not expecting to operate at the time. Tri-State does not believe any exemption would be in the best interest of the BES.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

The IESO strongly believes that the standard should apply to all the generating units whose capacity is being counted on, including those providing sufficient reserve to withstand a cold weather event.

Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA supports the comments submitted by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	
Response	

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

The proposed changes are subjective and allow for the exclusion of the very units this project should be attempting to make more reliable and resilient, which is those called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. The exclusion of these generators could be detrimental to the reliability and resilience of the BES. The inability of such generators to operate in extreme conditions could manifest as a false sense of security and ultimately contribute to the emergency rather than help alleviate it. Further, if the language were to remain as proposed, there is no explanation or definition on determining units as “plan to operate” or “do not operate” during the winter season.

The MRO NSRF suggests that all BES generators should be included in proposed section 4.2 and therefore the language should remain unchanged from EOP-011-2, section 4.2 Facilities. BES generators such as summer peaking units or those that do not plan to operate in the winter season would have the opportunity to declare exemption through R1.4.4.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the NAGF comments and agrees that since existing plants should not be required to retrofit and only provide their operational constraints a winter season is not necessary.	
Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
HQ experiences winter peaking months	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No

Document Name	

Comment
Note: BES generating units only; NERC rules do not extend to all Market Participants Problematic phrasing? 4.2. Facilities: For purposes of this standard, the term “generating unit” means those Bulk Electric System generators that plan to operate during the winter season. The winter season will be determined by the generating unit’s applicable Balancing Authority. The definition excludes those generators that do not operate during the winter season except and are not otherwise required by the BA to be available during Capacity Emergencies or Energy Emergencies. ISO-NE agrees with the SRC Comments for the proposed Applicable Facilities language and reiterates the concern; Can units operate during one winter season and not the next or vice versa? If so, how will this be treated under the standard since the implementation period is longer than one year? The SRC views this as problematic as units could opt in and out of operating during the “winter season” to avoid the regulation, thereby negating the intended benefits of this standard.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	No
Document Name	

Comment
Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment
The information in the Facilities section is unclear. The phrase “BES generators that plan to operate during the winter season” is unclear and confusing. Equipment does not plan anything. Is the language referring to Generator Owners or Generator Operators that plan to operate generating units during

the winter? It is unclear if the exclusion of “generators that do not operate during the winter season” refers to Generator Owners, Generator Operators, or generating units. It is unclear why generating units that would be called upon during certain Emergencies would be exempt from requirements that arose out of equipment failures to perform during emergency situations.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E supports the comments provided by the North American Generators Forum (NAGF).

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	No
Document Name	

Comment

NCPA agrees with the comments of MRO NSRF.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPCO signed on to ACES comments below:

In regards to the proposed Section 4.2 Facilities definition: In order to ensure a reliable response from generators that may be called upon by the Balancing Authorities during Capacity and Energy Emergencies, we recommend eliminating the exception for generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. Our recommended change to the language would be “The term excludes those generators that are not expected to operate during the winter season under normal and/or emergency conditions.”

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards.   To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 5

Answer	No

Document Name	
Comment	
NCPA agrees with the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No; capacity emergencies occur in all seasons, especially winter. An exemption for generation unit(s) will continue the trend of units not being weatherized and fall short of the overall goal, which is to prevent a repeat of the February 2021 severe winter storm event. Any specific criteria for any such exemption(s) should be included in the actual requirement wording. We do have a concern that some generators will just say they do not operate during the winter and thus create further winter capacity issues.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	No

Document Name	
Comment	
No; capacity emergencies occur in all seasons, especially winter. An exemption for generation unit(s) will continue the trend of units not being weatherized and fall short of the overall goal, which is to prevent a repeat of the February 2021 severe winter storm event. Any specific criteria for any such exemption(s) should be included in the actual requirement wording. We do have a concern that some generators will just say they do not operate during the winter and thus create further winter capacity issues.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
CEG suggests eliminating reference to winter and refer only to “intend to operate in cold weather”, the subject of the Standard. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Agree with NAGF comments	
Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
The language used, such as "do not operate" or "plan to operate" is unclear and confusing and could potentially exclude those very generating units that would be called upon during certain Emergency situations.	
Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5	
Answer	No
Document Name	
Comment	
CEG suggests eliminating reference to winter and refer only to "intend to operate in cold weather", the subject of the Standard. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	
WECC agrees with the concept, but the proposed wording appears to allow each individual GO to determine if it plans to operate during a winter period. Ambiguity could be reduced (and a more consistent use of the term "winter season" could be achieved) by modifying Applicability Section 4.2 to read: "For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that have been studied as "in operation" during winter seasonal studies and base cases performed by the PC or TP where the unit is located. Nothing in this standard is intended to prevent requesting the operation of any generating unit by a Balancing Authority during Capacity Emergencies or Energy Emergencies." An alternative option may be to include language such as "entities that offer generation day-ahead during the winter season" or "entities whose generation is picked up in the day-ahead market."	

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
A winter exemption creates potential BES reliability challenges from a resource planning, reserve margin, forecasted load, etc. perspective. Duke Energy does not agree with the proposed winter weather season unit exemption unless meaningful, enforceable, defined, and vetted exemption criteria are developed and incorporated into the proposed Standard.	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
The phrase “do not operate during the winter season except when called upon by the BA needs a standalone definition. Most entities have units that are only called upon during extreme weather events.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	
Answer	No
Document Name	
Comment	
We may be in agreement with the intention, but the language needs revision. All generators not planned to run during the winter should be excluded. Is this the intention? If so, the last sentence in 4.2 Facilities should read, “The term excludes those generators that are not included in the winter season	

plan.” As mentioned in LPPC comments, a separate Requirement should be included in EOP-012-1 which defines “winter season” AND identifies the units. If this were the case, no mention of emergency is needed.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
As drafted the applicability of the standard may create adverse impacts on competitive electricity markets in that it may disincentify Market Participants from operation during winter months due to a higher burden of compliance. Capital Power encourages the SDT to ensure the applicability of the standard considers NERC’s Market Principles and all types of Market Partipants, including those that may not be unable to recover costs by passing them through to end users (ie. Independent Power Producers). In general, Capital Power supports the NAGF comments on this question.	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	

In lieu of R1 of EOP-012-01 we recommend that R2 of EOP-011-03 be enhanced to require each BA to quantify the amount of reliable generation it needs to meet extreme cold weather conditions and place the requirement on the BA to identify the specific generators that are designated to provide the service under the BA's specified ambient conditions. This also has the benefit of ensuring that the amount of reliable generation and the degree to which the generation is reliable, including attributes besides freeze protection, is matched closely with the BA's mitigating requirements of R2. This proposal would achieve similar or better reliability benefits at less cost than the current proposal. The BA would also be able to match the weatherization requirements with their regional fuel needs; it is unnecessary and inefficient to require generators that likely may not be able to operate for reasons other than freeze protection (e.g., fuel unavailability, environmental limitations, cooling water supply issues, etc.) to winterize to such an extreme requirement. The BA may also be able to include financial incentives and penalties for absolute performance (i.e., no excuses) in its tariff design that cannot be replicated in a Reliability Standard; we foresee circumstances where generators may make made good faith efforts, comply with the Reliability Standards, but ultimately fail to perform during extreme cold weather events.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment

In regards to the proposed Section 4.2 Facilities definition: In order to ensure a reliable response from generators that may be called upon by the Balancing Authorities during Capacity and Energy Emergencies, we recommend eliminating the exception for generators that do not operate during the winter season except when called upon by the Balancing Authority to be available during Capacity Emergencies or Energy Emergencies. Our recommended change to the language would be "The term excludes those generators that are not expected to operate during the winter season under normal and/or emergency conditions."

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No
Document Name	

Comment

Although EGP agrees with the applicability of EOP-012-1, the language in the draft should be clarified. The term "generating unit" in section 4.2 and throughout the draft standard causes confusion in how the standard applies to renewable resources. Although an attempt to clarify is provided, the term generating unit refers to each and every individual turbine or invertor. It is recommended to use the term "generating resource." The term "generating resource" was adopted during the development of PRC-024 to resolve the same issue.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The SRC does not agree with the applicability of EOP-012 as drafted as NERC standards do not obligate a unit to declare their intent to operate by season. In addition, the Implementation Plan for this project provides anywhere from 18 months to 60 months (18 + 42 months) to comply with various requirements under the standard. The ability for a Generator Owner to alter its operability status during the "winter season" on an annual basis has the potential to negate the anticipated improvements that would be realized under this standard. Flexibility associated with applicability of the standard has the potential to reset the clock such that the improvements may never be realized. The SRC proposes the *following language* in replacement of the SDT proposed EOP-012-1 4.2 **Facilities section:**

For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan or otherwise are obligated to be available to operate during the winter season, including Blackstart Resources, as determined by the Balancing Authority. The winter season is defined as December through February unless the applicable Balancing Authority decides otherwise. Each Generator Owner shall notify its applicable Balancing Authority if meeting the exemption to this section.

(Please note: ERCOT supports the SRC comments to Question #3 but does not agree with the proposed language in its entirety. ERCOT will provide separate comments to address this discrepancy.)

The SRC proposes this change since a number of RTOs/ISOs have obligated units which are deemed capacity resources to be available when called upon in emergencies irrespective of the particular season. The language as originally drafted would inadvertently tend to create unnecessary ambiguity as to those obligations by not requiring such units to be available if they don't 'plan to operate in the winter season' (NOTE: Use exact language of original proposal). Section 215 (d)(6)of the Federal Power Act and FERC's implementing rules note the need for harmonization of NERC Standards with RTO/ISO market rules and not work against RTO/ISO market rules. The concern with the current proposed EOP-012-1 Applicability section: 4.2 Facilities is the exemption of certain units from having to winterize even if they have been designated as capacity resources to be called upon to operate to meet capacity emergencies. The proposed language would fix this problem without changing the overall approach proposed by the authors.

From the Joint Inquiry Report:

There are multiple references within "the Report" for BAs and RCs to be aware of specific generating unit limitations, such as ambient temperatures or fuel supply." The recently approved NERC Standards require the RC (IRO-010-4) and TOP and BA (TOP-003-5) to have provisions for notification from BES generating unit(s) to TOP and BA during local forecasted cold weather to include: Operating limitations based on: capability and availability; fuel supply and inventory concerns; fuel switching capabilities; and environmental constraints; and generating unit(s) minimum: design temperature; or historical operating temperature; or current cold weather performance temperature determined by an engineering analysis. This GO cold weather data criteria was included in EOP-011-2, R7 and is now moved to EOP-013-1, R3 and is where GO cold weather preparedness plans now reside (per Project 2021-07). However, the facility section of EOP-011-2 used the term "generating unit" to mean all BES generators and does not apply a generating unit exclusion as currently proposed in EOP-012-1. Any generating unit taking the exclusion under the Facilities section of EOP-012-1 will not be subject to EOP-012-1 Requirements. While the TOP may still request cold weather data (i.e. generating unit minimum operating temperature) per TOP-003-4 or TOP-003-5, the determination and evaluation by the generating unit may not serve as a basis to predict whether or not the unit will be able to perform during predicted cold weather if the unit is not performing the operating temperature limit analyses as well as related limitations, as defined in the EOP-012-1 Requirements. Per 'The Report', "The Event demonstrated that ambient temperatures alone do not serve as a basis to predict whether a generating unit can perform during predicted cold weather. For 81 percent of the generating units outaged, at the time the outage occurred, ambient temperatures were above the generating unit's stated design criteria." The concern is the information communicated from the GO to the BA / TOP may be limited and unreliable if units are set to different methods of criteria in determining unit limitations.

Per the Report: "TOP-003-5 R1 and R2 (effective April 1, 2023) will require TOPs and BAs, respectively, to include in their data specifications, to the GO, requests for information "during local forecasted cold weather" about generating units' operating limits, including "capability and availability; fuel supply and inventory concerns; fuel switching capabilities; and environmental constraints," as well as minimum temperature, based on one of three options. A related requirement, EOP-011-2 R7.3 (also effective April 1, 2023), will require GOs to develop cold weather preparedness plans which include, at a minimum, their generating unit(s)' cold weather data such as the aforesaid capability, fuel supply concerns, environmental constraints, etc. The intent behind requiring GOs to identify and share with the BAs and TOPs the expected limitations of their generating units "during local forecasted cold weather, is to prevent grid operators from being surprised when large numbers of generating units that had committed to run are unable to do so during cold weather events." This exchange of accurate generator unit operating limitations will be limited by those generating units no longer subject to a cold weather preparedness and may result in TOPs and BAs not being provided the correct operating limits in performing Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. By removing the unit exemption in EOP-012-1, the unit will perform the operating limitation analysis that meets the current Standard (EOP-011-2, effective April 2023 and newly proposed EOP-012-1) and allows for accurate TOP/BA assessments in preparing and operating in cold weather conditions.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 5

Answer	No
Document Name	

Comment

We may be in agreement with the intention, but the language needs revision. All generators not planned to run during the winter should be excluded. Is this the intention? If so, the last sentence in 4.2 Facilities should read, "The term excludes those generators that are not included in the winter season plan." As mentioned in LPPC comments, a separate Requirement should be included in EOP-012-1 which defines "winter season" AND identifies the units. If this were the case, no mention of emergency is needed

Likes 0	
Dislikes 0	

Response

Ashley Scheelar - TransAlta Corporation - 5

Answer	No
Document Name	

Comment

TransAlta agrees with exempting the facilities identified. Many generators in the North, particularly Canada, successfully operates in extreme cold year after year. In addition, many facilities operate in regions that do not have the type of reliability risk being addressed by this standard. For those entities, this standard is creating a significant administrative burden. Therefore, there should be further language that exempts those generators in regions where there is little or no reliability risk.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	

Comment

NRG generally agrees with the concept on exemptions for summer run only units. Typically penalization of unit operation is related to market rules. Therefore penalties should not be considered under NERC jurisdiction. However, if this becomes a NERC requirement, this could unfairly subject an entity to double jeopardy.

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	Yes
Document Name	

Comment

NRG generally agrees with the concept on exemptions for summer run only units. Typically, penalization of unit operation is related to market rules. Therefore, penalties should not be considered under NERC jurisdiction. However, if this becomes a NERC requirement, this could unfairly subject an entity to double jeopardy.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes

Document Name	
Comment	
FirstEnergy agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro appreciates the opportunity to comment and has the following comment seeking additional clarification on the assessment of the freeze protection measures, specifically for generating facilities that are not directly exposed to extreme cold, i.e. located at least partially indoors. BC Hydro's understanding is that the required assessment will be on facility-by-facility basis (or type of facilities), and will need to account for all equipment that would be exposed to extreme cold temperatures. Please confirm whether our understanding is accurate.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
This is already an industry standard/best practice.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	Yes

Document Name	
Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the EEI comments. In addition, Southern would like more clairity on the definition of “non-winter units” and what criteria would deem a unit to be exempt from the requirements of EOP-012-1. We also suggest defining what advance notice is required when detemiming and communicating which units are exempt from EOP-012. We suggest modifying the wording in 4.2 from *“For purposes of this standard, the term “generating unit” means those Bulk Electric System generators that plan to operate during the winter season.”* to *“For purposes of this standard, the term “generating unit” means those Bulk Electric System generators that **are expected** to operate during the winter season by their applicable BA.”*	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP supports the exclusion of units designated for summer peaking-only from the requirements of EOP-012-1, and supports the comments of EEI in that regard. AEP recommends that 4.2 (Facilities) be revised to state “… the term excludes those generators, *as defined by the Balancing Authority*, that do not operate…”	

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	Yes
Document Name	

Comment

Invenergy agrees with the applicability of EOP-012-1 as drafted.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	Yes
Document Name	

Comment

While we agree with having the BA determine, there needs to be a requirement for coordination amongst adjacent BAs. They don't have to have matching definitions but they need to understand the implications of having one BA with a dramatically different definition than its neighbor.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment

AZPS supports the SDT’s approach to exempt generating units that do not operate during the winter season. As noted by EEI, the term ‘peaking’ is not used in the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the SDT’s approach, which exempts units utilized for all periods except for the winter season, noting that the term “peaking” is not used in the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	
The SDT appropriately focuses the draft standard on winterization measures, as emergency grid conditions tend to occur more frequently in the winter than in the summer season. The draft standard also appropriately limits those winterization requirements to resources that operate in winter, as there is no need for a resource that does not operate in the winter to establish or maintain winterization measures.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	

No comments.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 6

Answer	Yes
Document Name	

Comment

An exemption for units only operated in the summer months would be welcome.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	Yes
Document Name	

Comment

Xcel Energy supports the comments submitted by EEI and the NAGF.

Likes 0	
Dislikes 0	

Response

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC

Answer	Yes
Document Name	

Comment

No additional 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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
RSC requests that the SDT consider Emergencies in the summer weather season that may warrant protection.	
Likes 0	
Dislikes 0	
Response	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	
EOP-012-1 should only be applied to units that participate in the market during the winter season. Note that the potential cost implications of R1 which can be millions if not tens of millions of dollars, which may result in generators either retiring or opting out of the winter season. Unfunded mandates such as R1 that have such a high material economic impact may ultimately reduce winter season reliability due to reduced generation available for dispatch.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #3.	

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	

Comment

MidAmerican supports EEI's comments and supports the SDT's approach, which exempts units utilized for all periods except for the winter season, noting that the term "peaking" is not used in the Reliability Standard.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

SIGE is responding with "Yes"; however, SIGE does not currently have units identified for summer peaking purposes only.

Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)	
Likes 0	
Dislikes 0	
Response	
Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
PPL NERC Registered Affiliates support EEI comments on Question 3.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	Yes
Document Name	
Comment	
Nv Energy supports EEI’s comments and supports the SDT’s approach, which exempts units utilized for all periods except for the winter season, noting that the term “peaking” is not used in the Reliability Standard.	
Likes 0	
Dislikes 0	

Response	
Hillary Dobson - Colorado Springs Utilities - 3	
Answer	Yes
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Please see answer to question 2. If the GO can demonstrate via historical data or technical justification that it does not or can't operate during a heightened cold weather event, some form of exemption should be available to avoid required must run mandate during cold weather-related energy emergencies. The standard must avoid forcing the closure of generation units from untenable compliance requirements. However, this should not relieve such Facility from winterizing plans to assure the generation units will not suffer damage rendering them unavailable upon return to warm weather conditions. Example: Generation unit is inaccessible during snow season road closure.	
Likes 0	
Dislikes 0	

Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Calpine agrees that EOP-012-1 should only be applied to units that participate in the market during the winter season. This will limit costly winterization requirements to those resources that actually operate in the winter, alleviating any need for a resource that does not operate in the winter from undertaking costly measures that will not provide real benefits. Additionally, imposition of expensive winterization measures for resources that do not operate in the winter season could result in generators either retiring or opting out of the winter season entirely, potentially impacting reliability.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Q3. ERCOT suggests the applicability language for facilities in Section 4.1.2 be revised as shown below. "Plan to operate" is not sufficiently clear, as neither the Regional Entity nor the BA, RC, or PC can know the GO's subjective intentions. Accordingly, the BA should decide not only how winter should be defined for the BA Area, but also whether a generating unit is obligated to be available under the relevant rules. To the extent the SDT determines that the BA's responsibility to identify units that are covered by the standard should be stated more explicitly within the requirements, ERCOT would support that change. **ALTERNATE LANGUAGE PROPOSED:** *For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan, or otherwise are obligated, to be available to operate during the winter season, including Blackstart Resources, as determined by the Balancing Authority. The winter season is defined as December through February unless the applicable Balancing Authority decides otherwise. A list of those units exempt from this standard for a given winter season shall be maintained by the Balancing Authority.*	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes

Document Name	
Comment	
LCRA generally agrees with the concept on exemptions for summer run only units. Typically, penalization of unit operation is related to market rules. Therefore, penalties should not be considered under NERC jurisdiction. However, if this becomes a NERC requirement, this could unfairly subject an entity to double jeopardy.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
LCRA generally agrees with the concept on exemptions for summer run only units. Typically, penalization of unit operation is related to market rules. Therefore, penalties should not be considered under NERC jurisdiction. However, if this becomes a NERC requirement, this could unfairly subject an entity to double jeopardy.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Vinson - American Clean Power Association - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
N/A- SEC does not operate under winter weather conditions as much of the United States does, therefore, SEC has no opinion.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees with and supports proposed Reliability Standard EOP-012-1. Texas RE is concerned, however, with section A. 4.2. The Facilities language does not indicate that it is exempting those units utilized for summer peaking purposes only as this question states. Texas RE recommends clarifying that any generating unit that could be called upon by the BA be included in the applicability of EOP-012-1. Those entities who are needed at during Capacity Emergencies and Energy Emergencies need to be appropriately prepared for extreme weather.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	

NAGF Comments: As drafted, the applicability section is likely to drive rational Generator Owners from the winter period due to the uncertainty of what may be required to meet the obligations in the EOP-012-1 requirements. Additionally, it appears that the Balancing Authority could call upon a generator to run during a period that is not considered a Capacity or Energy Emergency and thereby cause the generator to be subject to the standard. As worded, it is unclear if the Balancing Authority can only call upon the generators once an emergency has been declared by the Reliability Coordinator or if the Balancing Authority is anticipating an emergency. Each of these issues would need to be addressed to ensure the potential for unintended consequences is reduced.

The NAGF is providing a revised OP-012-1 standard for consideration that addresses these issues in a holistic manner.

Generators should not be placed in a position that by running they become subject to a standard ***unless they have contracted/agreed*** with an entity, to provide that service, similar to EOP-005. Under EOP-005, all generators capable of providing blackstart service are not required to comply; compliance is mandatory only for those generators that have contracted for blackstart service. EOP-012 should only apply to those generators that have agreed to be available to provide service under all conditions, not just by operating during specific months or time periods during the year.

Likes 0	
Dislikes 0	
Response	

Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	
Response	

Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	
Document Name	

Comment

At this current time, this is not applicable to Entergy.

Likes 0	
Dislikes 0	

Response

Jun Hua - Austin Energy - 4

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.

Likes 0	
Dislikes 0	
Response	

4. Does the proposed language in EOP-012-1 requirement R1 that require existing units to implement new freeze protection measures or modification of existing freeze protection measures, raise any stakeholder concerns? If so, please provide details of the concern, suggestions to the proposed language that addresses the risk presented in recommendation 1f, and if appropriate, technical or procedural justification.

John Babik - JEA - 5	
Answer	No
Document Name	
Comment	

JEA believes that continuous operations at a single recorded temperature will be a significant undertaking (cost, manpower, active maintenance & associated risks) without much benefit in Jacksonville, FL. Our lowest temperature was in 1985 at 7 degrees F for two hours, but our mean low for December, January, and February is 28, 25, and 28 degrees F. To operate for 7 degrees F continually even during the winter season will place a strain on resources, requiring heat tape where insulation would be sufficient (based upon a conservative forecast).

Some exclusion for regions that experience minimal freezes should be considered. For example, "If hourly temperature data shows that the entity experienced less than 10 five-hour freezes in the past five years, continuous operation at the minimum temperature is not required." This is a suggestion, but a suitable expert could be consulted to suggest a time element (X-hour freezes) with a suitable number of cases (Y instances) over a recent time period (past Z years).

Likes 0	
Dislikes 0	
Response	

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

Q4. The proposed language in EOP-012-1 R1 causes concerns for ERCOT. ERCOT generally supports the SRC comments provided; however, the SRC comments do not encompass all of ERCOT's concerns. These concerns are explicitly identified below and are followed by proposed language. For clarity, ERCOT also addresses its concerns with the CAP and declaration/exemption in this response, as those issues are interrelated.

- R1, in general: should identify the Generator Owner as the entity taking action, not the generating unit.
- R1.1: The use of the word "designed" may imply that existing generators should be redesigned to comply with the defined temperature standard. It is more accurate and more straightforward to phrase this as a capability requirement rather than a design requirement.
- R1.1: Should require the GOs to use an objective source of historical temperature data to be implemented consistently across regions.
- R1.2 and R1.3: Should be more explicitly tied to R1.1 and the ability to be capable of continuous operations. The FERC/NERC Report on the February 2021 Cold Weather Outages states that GOs should "understand how precipitation and the accelerated cooling effect of wind limit their generating unit's performance." The Report further states that the February cold weather event demonstrated that ambient temperatures alone do not serve as a basis to predict whether a generating unit can perform during predicted cold weather. Also, ERCOT urges the SDT to adopt a clear metric for wind speed and precipitation. ERCOT is not presently proposing specific metrics. If the SDT's preference is to address this in Phase 2, ERCOT is comfortable with that.

- R1.2 and R1.3: Similar to comment for R1.1, should not reference unit design.
- R1.4: The meaning of “existing” will change over time. If purpose is to limit this provision to those in existence at the time this rule goes into effect, as distinct from “new” generating units, which presumably enter operations at some later date, the language should say that.
- R1.4: Propose to remove CAP details from R1 and move to a standalone requirement, presented here as R7. It is more concise to have one CAP section since the need for a CAP could be triggered by several requirements.
- R1.4: The CAP requirement should apply to all GOs, since any GO can discover an inability to comply at some point (even outside of the review required by R4 or the circumstances identified in R6). The modifications proposed also require the CAP to be implemented as soon as practicable with a reasonable window for actions with long lead times.
- R1.4.2 (relocated to ERCOT proposed R7.2): Each timetable needs to identify the measures that will be implemented by each winter season.
- R1.4.4: ERCOT provides language to replace the declaration language with explicit exemption language in a new R8. If this is intended to operate as an exemption, that needs to be said explicitly, and it needs to be subject to some reasonable constraint. Recommendation 1f in the FERC/NERC Report does not contemplate any sort of broad exception; however, ERCOT agrees that a narrow exception to avoid retirements is helpful. ERCOT believes that the exemption language provided in R8 better achieves the purpose of the declaration while also improving on the concept by ensuring periodic reviews to ensure the constraint is still valid.

As noted, the revisions to the CAP and exemption language would also apply to R4 and R6. The comments and proposed language revisions to these requirements are as follows:

- R4.1 and R4.2: Clarify that revisions to cold weather preparedness plan need to be made as necessary.
- R4.3: Require a CAP using language similar to that used in R1.4. This addresses a potential gap of modifying the freeze protection measures to updated temperatures.
- R6: Remove “within the Generation Owner’s control.” All GO equipment should be understood to be within the GO’s control, as ownership should determine ultimate legal control. Otherwise, this would create a gap in the standards. If another party owns equipment at the site that could cause a failure, the GO can assign that party responsibility through contract.
- R6: Remove CAP details here in favor of general CAP provision in R7. Add similar CAP introduction language as seen in R1.4 and R4.3.
- R6: Include subparts 6.1 and “similar” language from subpart 6.2.3 from the SDT proposed standard language in the main requirement to avoid the need to put the language in the CAP section (R7).
- R6: This should reference the min hourly temp since 1/1/75, not the min capable operating temp in 3.4.2.

ALTERNATE LANGUAGE PROPOSED (REDLINE VERSION ATTACHED TO QUESTION 10)

R1. Each Generator Owner shall implement freeze protection measures that ensure each of its generating units meet the following minimum criteria:

1.1. Each generating unit shall be capable of continuous operation at the minimum hourly temperature recorded by the National Oceanic and Atmospheric Association or Environment and Climate Change Canada since January 1975 at the weather station nearest to the generator’s location;

1.2. For purposes of identifying freeze protection measures needed to comply with Part 1.1, the Generator Operator shall account for the cooling effect of wind at XX mph;

1.3. For purposes of identifying freeze protection measures needed to comply with Part 1.1, the Generator Operator shall account for the impacts of YY precipitation (e.g., sleet, snow, ice, and freezing rain); and

1.4. If a Generator Owner determines that a generating unit requires either new freeze protection measures or modification of existing freeze protection measures to meet the standard established in Part 1.1, the Generator Owner shall develop a Corrective Action Plan (CAP) in accordance with Requirement R7. The CAP shall be developed within 150 days of identifying the need for new or modified freeze protection measures and shall be implemented as soon as practicable but no later than three years from the date the deficiency was identified.

R4. Once every five calendar year, each Generator Owner shall:

4.1. Review the documented minimum hourly temperature developed pursuant to Part 3.1, and, if that temperature is no longer accurate, update the cold weather preparedness plan with the lowest temperature and make any necessary revisions to the plan based on that lower temperature;

4.2. Review its documented cold weather minimum temperature contained within its cold weather preparedness plan(s) for its generating units, pursuant to Part 3.4.2, and update that value as necessary; and

4.3. Review whether its generating units have the freeze protection measures required to comply with Requirement R1 and, if not, develop a CAP in accordance with R7 and implement the CAP as soon as practicable but no later than three years after identifying the need for new or modified freeze protection measures.

R6. Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner's equipment, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature described in Part 1.1 shall develop a CAP, in accordance with R7, for each generating unit that experiences such a failure and for any other of the Generator Owner's generating units that uses similar equipment that could reasonably be susceptible to a similar failure. The CAP shall be developed within 150 days of the event or by the following July 1, whichever is earlier, and shall be implemented as soon as practicable but no later than three years from the date the CAP is developed.

R7. A Corrective Action Plan (CAP) required by this standard shall include at least the following:

7.1 An identification of corrective actions needed for the affected unit to comply with Requirement R1, including any necessary modifications to the Generator Owner's cold weather preparedness plan;

7.2 A timetable for implementing the corrective actions from Part 1.4.1, Part 7.1, or Requirement R6, as applicable, which shall identify the measures that can reasonably be achieved before each successive winter season and the timetable for implementing each such measure, and documentation of the commercial, technical, or other reasons for the timetable provided;

7.3 An identification of any temporary operating limitations that would apply until execution of the corrective actions identified in the CAP;

7.4 Explanation of, and documentation for, any exemption claimed pursuant to Requirement R8; and

7.5 For any CAP required by Requirement R6, a summary of the identified cause(s) for the equipment freezing event, where applicable, and any relevant associated data.

R8. Notwithstanding any other requirement in this standard, if a generating unit identified in Part 8.1 or 8.2 cannot comply with Requirement R1 due to a technical, commercial, or operational limitation, the generating unit shall be exempt from compliance with R1 to the extent of that limitation if the Generator Owner can provide documentation sufficient to demonstrate that limitation. In the case of a commercial limitation, the Generator Owner shall provide documentation sufficient to demonstrate that the generating unit would reasonably be expected to operate at a financial loss on an annual basis if it were required to comply with the standard. In each case, the Generator Owner shall ensure that the unit complies with Requirement R1 to the greatest extent of its capability. This exemption applies only to the following generating units:

8.1 Any generating unit that began operating before the compliance date for Requirement R1, or

8.2 Any generating unit that began operating on or after the compliance date for Requirement R1, if the asserted technical, commercial, or operational limitation is attributable to either a lower minimum temperature experienced after the unit became operational or some other condition not reasonably foreseeable at the time the unit began operations.

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	No

Document Name	
Comment	
R1.4.4 is a critical requirement that recognizes the technical, commercial and operational constraints when implementing modifications to existing freeze protection measures. Support for R1 is contingent on the retention of this specific requirement, as without it, Generators could face unreasonable commercial, technical or operational obstacles to maintaining compliance.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
The requirement has the following problems which should be addressed: 1) "Generating unit" defined simply as "Bulk Electric System Generator that… operate[s] during the winter season" needs further defining limitation. Should this only encompass the generator and its supporting structure? For example, is the powerhouse enclosing hydro units the boundary? Is the switchyard associated with a distributed generation aggregation point excluded? If the ERO later defines "generating unit" also includes all facilities the GO owns, such as the generation transmission interconnection line, is this intended by the SDT? 2) Hourly temperature may be a challenge to attain back to 1975. Suggest allowance of daily minimums and highs for historical records before the standard effective date since this data is more easily obtained and require hourly after the standard is implemented. The NOAA maintains numerous weather data collection sites and the GO should be able to utilize the nearest NOAA site to the generating unit location. This can be included within Measure M1. If the objective for hourly data is merly to document time spans temperatures are below freezing, state this and allow other forms of documentation. Retention of hourly data outside the area of concern adds unnecessary compliance burden. 3) Allow exemption for generation units that can demonstrate continuous operations through 5 days (not necessarily contiguous) where recorded temperature in Celsius was between -10 and 0 degrees or lower. 4) Stating "generation unit design" could create subjective audit interpretation as being from the generator manufacturer. Such data is not likely available for older units. Suggest revising requirement R1 to state "Each Generator Owner… implement mitigation measures at each generating unit for freeze protection based on the following minimum criteria." Further, remove "generator unit design" from the subsections to clarify "design" refers to the mitigating measure. For example: "design to enable continuous operations…" and "design shall account for…" This will allow for both generator modifications to its manufacturer design and measures to mitigate around manufacturer design parameters that can't be changed. 5) Assure that failure of a mitigating measure is not a compliance violation. Please consider revising section 1.4 to make this clear, such as "should protective mitigating measures prove inadequate…"	
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 Regional Standards Committee	
Answer	No
Document Name	
Comment	
For some Canadian entities, units already operate in cold weather annually from November to March. These requirements represent an added administrative burden. The new reliability standards requirement should be part of a regional variance for the regions where winterization programs are not in place. Canadian entity generators already operate successfully in cold climates with extreme conditions. For such entities, this is an additional compliance burden, with no additional benefit to grid reliability	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
NCPA agrees with the comments of NRG Energy, Inc.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler	

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	No
Document Name	

Comment

NCPA agrees with the comments of NRG Energy, Inc.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

we support the RSC comments.

For some Canadian entites, units already operate in cold weather annually from November to March. These requirements represent an added administrative burden.

The new reliability standards requirement should be part of a regional variance for the regions where winterization programs are not in place. Canadian entities generators already operate successfully in cold climate with extreme conditions. For such entities this is an additional compliance burden, with no additional benefit to grid reliability.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro appreciates the opportunity to comment and has the following comment seeking to confirm our understanding against the intent of Requirement R1 of proposed EOP-012-1 (Draft 1) as follows. Following an assessment of the existing generating units' freeze protection, if determined that the freeze protection measure are adequate and meet the criteria set out in Requirement R1 of proposed EOP-012-1, then there would be no need to "implement new freeze protection measures or modification of existing freeze protection measures", i.e. no Corrective Action Plan will be required per Requirement R1 Part 1.4.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
The IESO requests removing the 'commercial' reference in Requirements 1.4.2 and 1.4.4 as this language is vague, creates an ambiguity as to the obligation otherwise provided for in the standard, and a review of commercial issues is not within NERC's domain and expertise. 1.4.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical or operational constraints, as defined by the Generator Owner; 1.4.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and 1.4.4. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document technical or operational constraints as defined by the Generator Owner as support for such declaration.	

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

Idaho Power is proposing the following language modification due to the fact that manufacturers do not provide design data. Propose in R1.1-1.3: Each generating unit shall be capable of continuous operations either by design data or by operational data documented minimum hourly temperature.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Tacoma Power is concerned that the proposed language in EOP-012-1 R1, as well as Parts 3.1 and 4.1, places significant administrative and analytical burden on entities, and potentially complicates the assessment of design capabilities. Tacoma Power is concerned that collecting and maintaining hourly temperature data would amount to finding a needle in a haystack (over 400,000 data points in a 50 year time period). Instead, Tacoma Power recommends utilizing annual temperature data to identify the lowest temperature recorded for the year. This approach results in a smaller set of data to maintain and is easier for entities to identify the lowest temperature needed for freeze protection. Additionally, analyzing hourly data from summer periods is not beneficial, so a lowest recorded temperature for the year is more appropriate.

Tacoma Power recommends modifying Part 1.1, Part 3.1 and Part 4.1 to remove the Requirement for a specific interval, and only require documentation of the lowest recorded temperature since 1975, as follows. This change allows an entity to determine whether hourly, daily or annual is the most appropriate for their assessments.

Recommended changes to Parts 1.1, 3.1 and 4.1:

- Part 1.1: “Each generating unit shall be designed and maintained to be capable of continuous operations at the **lowest recorded ambient** temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.”
- Part 3.1: “**Lowest recorded ambient** temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;”
- Part 4.1: “Review the **lowest recorded ambient** temperature developed pursuant to Part 3.1, and update the cold weather preparedness plan with the lowest temperature as necessary.”

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	No
Document Name	

Comment

For some Canadian entites, units already operate in cold weather annually from November to March. These requirements represent an added administrative burden.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

No issues with the requirements.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ashley Scheelar - TransAlta Corporation - 5	
Answer	Yes
Document Name	
Comment	
TransAlta understands the challenges the STD has associated with developing appropriate risk based standards to deal with the effects of extreme weather on the grid. TransAlta respectfully provides the following feedback: The proposed language in EOP-012-1 requirement R1 does raise significant concerns. Facilities in particularly cold climates, such as Canada, would have significant freeze protection measures in place which means they do successfully operate in extremely cold conditions year after year. This standard presents us with the administrative burden of documenting and maintaining that documentation to describe basic facts about our facility as it relates to freeze protection measures with no benefit to the reliability of the grid in those regions. TransAlta also supports comments made by NRG Energy and NPCC Regional Standards Committee with regard to this question.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - Lower Colorado River Authority - 1	
Answer	Yes

Document Name	
Comment	
LCRA agrees with Lthe North American Generator Forum comments and NRG Energy Inc. comments submitted 6/15/2022.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
LCRA agrees with Lthe North American Generator Forum comments and NRG Energy Inc. comments submitted 6/15/2022.	
Likes 0	
Dislikes 0	
Response	
Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	Yes
Document Name	
Comment	
SNPD supports comments submitted by LPPC and Tacoma Power	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	

The SRC finds certain aspects of the proposed language as too vague and invites a lack of consistency among generators even those geographically close to each other. In terms of documentation of temperatures, we suggest that the standard be revised to propose the use of NOAA data as the default in determining the minimum hourly temperature, otherwise, provide supporting documentation of data used in determining the minimum hourly temperature. “At its location” may be too ambiguous and doesn’t represent enough specificity to accurately define weather conditions.

The SRC proposes the following EOP-012-1 R1.1 language *changes*:

R1.1. Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its *nearest National Oceanic and Atmospheric Administration (NOAA) or its Environment and Climate Change (for generating units located in Canada)* location since 1/1/1975 or a lesser period if reliable data is not available to 1975, *should the generating unit wish to utilize a different source of weather information it shall provide documentation as to whether its source is equivalent or superior to the NOAA data as support for using this alternative data source, which documentation of temperature value shall be audited;*

In addition, the SRC requests removing the ‘commercial’ reference in Requirements 1.4.2 and 1.4.4 as this language is vague, creates an ambiguity as to the obligation otherwise provided for in the standard, and a review of commercial issues is not within NERC’s domain and expertise.

R1.4.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, or operational constraints, as defined by the Generator Owner;

R1.4.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

R1.4.4. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that ***certain*** revisions to the cold weather preparedness plan(s) are ***not*** required and that ***certain*** corrective actions will ***not*** be taken. The Generator Owner shall document technical, or operational constraints as defined by the Generator Owner as support for such declaration.

Likes 0	
Dislikes 0	
Response	

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	TAPS proposed language Q4.docx
Comment	

We have a number of concerns related to clarity and consistency both within R1, and between R1 and other draft requirements.

“Designed and maintained to be capable of continuous operations”
Our most significant concern is the proposed language in R1.1: “Each generating unit shall be designed and maintained to be capable of continuous operations….” This language is significantly more specific, as well as narrower, than Recommendation 1f, and could result in a GO being found noncompliant with R1 based on an R6 Forced Outage, on the theory that if a unit is “designed and maintained to be capable of continuous operation” at the minimum hourly temperature, then a Forced Outage meeting the criteria of R6 should be impossible. We do not believe that to be the SDT’s (or FERC’s) intent; R1.1-R1.3 should require GOs to implement freeze protection measures that they reasonably believe will be adequate, which they will supplement and improve pursuant to R6 and R1.4 if an event reveals a shortcoming. We suggest that R1.1 be revised as follows, which parallels the wording of R1.2 and R1.3 but uses the words “based on” to reflect the common understanding of “design basis”: “The generating unit design shall be based on the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to

1975." If the SDT does not accept this proposed revision, it should at minimum (1) insert language clarifying that experiencing an R6 event is not evidence that a GO is in violation of R1, and (2) delete the words "and maintain" from R1.1, because maintenance of freeze protection measures is already required by R3.3.

Exceptions from R1.1-R1.3
We believe that the SDT intends that if an existing generator is developing and implementing a CAP pursuant to R1.4, or if an existing or new generator has determined (pursuant to R1.4.4 or R2, respectively) that technical, commercial, or operational constraints prevent it from meeting the criteria in R1.1-R1.3, then the GO will not be found noncompliant with R1.1-R1.3 on the basis of the issue(s) that are being addressed through the CAP or that are prevented by the constraint. But that intention is not expressed in the standard: R1 mandates "freeze protection measures based on" R1.1, R1.2, R1.3, and R1.4 as "minimum criteria," in all circumstances. And R1 does not even mention the possibility of new generators being unable to meet the criteria, as contemplated by R2. As currently written, a generator availing itself of R1.4 or R2 would be in violation of R1.1-R1.3. We have proposed language below clarifying that applicable generating units must meet the criteria in R1.1-R1.3 except to the extent that the GO is developing and implementing a CAP, or has documented technical, commercial, or operational constraints.

New vs. existing generators; combining R2 with R1.4.4
If the standard is to distinguish between "new" and "existing" generators—which we do not believe is necessary—then those terms must be defined for the purpose of this standard. In particular, the SDT would need to clarify two issues: (1) whether a generator's status as "new" or "existing" is fixed permanently based on some set date tied to the effectiveness of the standard (e.g. all generators in service on the state the standard becomes effective are "existing," and all that come online after that point are "new generators" throughout their lifespans), or whether the generator's status is instead determined at the time the standard is being applied (e.g. a generator that discovers the need for additional freeze control measures the day before it is to come online is a "new" generator, and thus must comply with R1.1-R1.3 immediately unless, per R2, a "technical, commercial, or operational constraint" prevents it from doing so, while a generator that makes the same discovery the day after beginning operations is "existing" and must develop and implement a CAP pursuant to R1.4). And (2) for a unit that is under development on the effective date of the standard (or other relevant date), or at the time it discovers the need for additional freeze control measures, at what point in the process of design, permitting, construction, and testing does a generator become "existing" rather than "new"?

It seems that the key difference in the treatment of "new" and "existing" generators in the draft standard is that "existing" generators develop a CAP if their freeze protection measures do not meet the criteria in R1.1-R1.3, and implement the CAP unless prevented by a technical commercial, or operational constraint, while "new" generators must meet the criteria in R1.1-R1.3 unless prevented by a constraint—in short, "new" generators skip the CAP step. This is not, in our view, a distinction that requires the definition of separate classes of generators. A simpler approach would be to revise R1 and merge it with R2 to provide three options for compliance for all generators: (1) if possible, have freeze control measures consistent with R1.1-R1.3; (2) if a generator's freeze control measures are not consistent with R1.1-R1.3, but it is feasible to supplement or modify them to make them consistent, develop and implement a CAP to do so; and (3) if freeze control measures consistent with R1.1-R1.3 are not feasible due to a technical, commercial, or operational constraints, document the constraint and review every five years. Please note that our proposed R1.5 below is based on the text of R2 and R2.1, not R1.4.4; as noted in response to Question 5 below, we suggest that R2.2's five-year review requirement be moved to R4, and thus have not included that subrequirement in our proposed redline of R1.

Lack of deadline in R1.4
Requirement R1.4 requires GOs to develop CAPs in some situations, but provides no deadline by which they must do so. The absence of a deadline places registered entities in the untenable position of having to guess, on a case-by-case basis, how long they have to develop a CAP before they would be deemed noncompliant. The standard should also specify which events trigger the need to develop a CAP pursuant to R1.4, i.e. under which circumstances a generator could need new or modified freeze protection measures. We believe that there are three situations with clear "trigger dates" in which a CAP could be required by R1.4: (1) implementation of this standard, where a generator's existing freeze protection measures do not meet the new criteria; (2) an R6 event, and (3) discovery of the need for changes to freeze protection measures through some other means, including an R4 review that results in either an updated minimum hourly temperature necessitating changes to freeze protection measures, or removal of a previously-documented technical, commercial, or operational constraint. (As explained below, we are suggesting that the CAP elements of R6 be moved to R1.4, leaving only the identification and analysis of the event in R6.) We suggest that CAPs developed when this standard first becomes effective, and in response to an R6 event, use the same deadline as currently proposed in R6: "150 days subsequent to the [event/effective date of this Requirement] or by July 1 that follows the [event/effective date of this Requirement], whichever is earlier." CAPs developed in response to some other means of discovery of the need for changes, including R4 updates, should be developed by July 1 of the year following the calendar year in which the review or other means of discovery takes place. This last class of CAPs should not use the same "by July 1 that follows the [completion of the review]" language as other CAPs, because doing so would force a GO that happened to complete a review or discover an issue in June to develop a CAP in less than a month. And development of such CAPs should have only a date deadline, not an alternative number of days; otherwise, a GO conducting numerous R4

reviews in a calendar year would have an incentive to delay completion of any reviews it thinks likely to result in the need for a CAP, in order to avoid having to develop CAPs at the same time it is continuing its review of other units).

Overlap between R1, R4, and R6
R1, R4, and R6 contain overlapping requirements; for the sake of clarity, and to avoid duplicative noncompliance situations, these overlaps should be eliminated and the relationships between the requirements clarified.
As currently drafted, R1 requires a CAP where a generator "requires either new freeze protection measures or modification of existing freeze protection measures." R4.3 requires each GO to "[r]eview whether its generating units have the freeze protection measures required to operate at the lowest temperature established pursuant to Requirement R1 and, if not, implement appropriate modifications per the requirements of Part 1.4." A GO that fails to "implement appropriate modifications per the requirements of Part 1.4" would thus be noncompliant with both R4.3 and R1.4. This issue could be remedied with a minor edit to R4.3: replace "and if not, implement appropriate modifications per the requirements of R1.4" with "If freeze protection measures must be supplemented or modified as a result of the updated lowest temperature, the requirements of Part 1.4 apply."
There is a similar overlap between R1.4 and R6, although R6 does not mention R1.4. R6 requires a GO that has experienced a qualifying event to develop a CAP meeting requirements essentially identical to those of R1.4, with the addition of two analysis requirements ("[a] summary of the identified cause(s) for the equipment freezing event where applicable and any relevant associated data" and "[a] review of applicability to similar equipment at other generating units owned by the Generator Owner"). As drafted, an R6 event would trigger the requirements to develop a CAP pursuant to both R6 and R1.4, unless the R6 analysis identified no need for changes to freeze protection measures. As with the overlap between R1.4 and R4, a failure to develop a CAP would result in an entity being noncompliant with two essentially identical requirements. We suggest replacing R6.2.3 through R6.2.6 with a statement that "Corrective actions in response to an analysis required by R6, including new or modified freeze protection measures, are subject to the requirements of Part 1.4." Language should be added to R1.4 to indicate that it applies to the incorporation of lessons learned pursuant to R6; and the R6.2.3 requirement to identify corrective actions for "identified similar units" can be added to R1.4.1, e.g. "and, if applicable, any similar units identified pursuant to R6.2.2."

Proposed language is attached in redline and clean format.

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	Yes
Document Name	

Comment

Calpine has concerns with imposition of the R1 requirements, without Key Recommendation #2 in the November 2021 FERC/NERC, report being addressed. This requirement to implement new or modified freeze protection measures without a cost recovery mechanism proposes a significant economic burden on generators, and will result in reduced generation available the winter season; it could even result in permanent retirement due to the significant cost of compliance. These outcomes will reduce grid reliability by decreasing the amount of available generation to the grid. Calpine proposes that the SDT instead focus on Freeze protection measures rather than full retrofits/redesigns of existing units (which may or may not be feasible depending on unit age, design, technical, commercial or operational constraints). Additionally, the SDT requirement should address only those critical components that could potentially trip offline or derate a generation unit due to sustained conditions. Root cause analyses of previous freeze-related outages have not revealed concerns for auxiliary systems that support operations, but are considered part of balance-of-plant equipment. Therefore, the focus should be on freeze protection of critical components only. These can be addressed through industry standard operational practices prior to freeze events. In summary, retrofits of existing units should not include all operating systems and should not be required without some

cost recovery realized. Calpine agrees with Texas Competitive Power Advocates (TCPA) in proposing that the SDT should consider ASHRE, a statistically-based standard which uses daily average temperatures, which has been accepted and used by industry for many years. Finally, particularly in the Texas RE region, or other regions susceptible to severe hot weather peaks, overdesigned cold weather protection will reduce hot weather reliability when the grid is most likely to experience peak demand. Without practical limit to winter preparation, summer reliability may be substantially reduced.

Likes 0	
Dislikes 0	

Response

Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Portland General Electric Company supports the survey response provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Hillary Dobson - Colorado Springs Utilities - 3	
Answer	Yes
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Requirement R1 would require the GO to implement new freeze protection measures or modify existing freeze protection measures if minimum criteria (part 1.1 through 1.3) are not met. Is there a definition or parameters for what the extent of that protection boundary will be? Will this apply to all climates or can GOs take graded approaches to the protective measures depending on the average temperature data?

We recommend splitting R1 into two parts:

Rephrase R1 to “Each Generator Owner shall document an evaluation of freeze protection measures for their applicable generating units taking the following into account:

1.1. The documented minimum hourly temperature experienced at each generating unit’s location since 1/1/1975 (or a lesser period if reliable data is not available to 1975);

1.2. The cooling effect of wind based on each generating unit’s design; and

1.3. The impact on each generating unit’s operations due to precipitation (e.g.,sleet, snow, ice, and freezing rain).”

Make the actions described in R1, part 1.4 a separate Requirement (new R2). Possible wording:

“R2 Based on the evaluation of freeze protection measures performed under Requirement R1, each Generator Owner shall:

2.1 Determine if a generating unit requires new or modified freeze protection measures, and if so develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

2.1.1. An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner’s cold weather preparedness plan(s);

2.1.2 A timetable for implementing the corrective action(s) from Part 2.1.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

2.1.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

2.1.4. A declaration, where deemed appropriate by the Generator Owner based on the review of Parts 2.1.1 through 2.1.3, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.”

Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

PPL NERC Registered Affiliates generally support EEI comments on Question 4, including the proposed language for R1 in the EEI comments. In addition, PPL and LG&E and KU believe both proposed EOP-012-1 R1 language and alternative R1 proposed by EEI could be more clear on how the GO would demonstrate that units comply with the requirements for freeze protection measures with respect to the cooling effect of wind and impacts of precipitation, particularly for existing units (see question 5 for new units). PPL and LG&E and KU recommend the wind and precipitation component of R1 be either removed (suggested language below) or the wind and precipitation criteria be more clearly defined.

1.1 Each generating unit shall be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975, or a lesser period if reliable data is not available to 1975;

1.2 For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

1.2.1 An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.2.2 A timetable for implementing the corrective action(s) from Part **1.2.1** which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.2.3 An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.2.4 In the event a GO is unable to fully mitigate their generating unit to have the continuous operating capability as defined under R1, a determination shall be made, where deemed appropriate by the Generator Owner based on **their** review of Parts **1.2.1** through **1.2.3**, that no **additional** revisions to the cold weather preparedness plan(s) **will be made** and that no further corrective actions will be taken. The Generator Owner shall document **the** technical, commercial, or operational constraints as defined by the Generator owner as support for such **determination**.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	Yes
Document Name	

Comment

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

While SIGE supports efforts to ensure that existing generating units have the ability to continuously operating within their designed operating specifications in extreme temperatures (cold or hot); SIGE does not agree that generating units should be required to make modifications to meet certain freeze protection requirements beyone the expected designed operating specifications.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	Yes
Document Name	

Comment

MidAmerican supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster

Answer	Yes
Document Name	

Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #4.	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
CHPD agrees with LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
In R1.1 it states “each generating unit shall be designed and maintained using the minimum hourly temperature since 1975…” Concern is that expenditures will be required for a temperature that may occurs once in decades or is an anomaly. Perhaps a solution would be to determine the frequency of minimum hourly temperatures that occur in the time period. The standard could read: “if an area has experienced at least 10 (or 5, or 8 or whatever) minimum hourly temperatures within a 10 degree range, ie (-10 to -20) (0 to -10), since 1975, the entity will use the lowest recorded hourly temperature that occurred within that range”. This could also eliminate the need for Requirments R4.1 and R4.3, since the probability of hitting lower temperatures using the 10 degree range method in a 5 year period would be minimized. Also R1.1 and R3.1 are redundant in wording….would flow better if the requirements are re-arranged, see comments for #10.	
Likes 0	
Dislikes 0	
Response	

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	
The requirements of R1, without addressing Key Recommendation #2 in the November 2021 FERC/NERC report is the most significant concern of the Texas generators. Unfunded mandates of this economic magnitude that do not have proposed cost recovery will result in reduced generation available the winter season, at the least, and permanent retirement, at the worst. Neither of these outcomes will enhance grid reliability. Quite the opposite, this requirement will very likely reduce grid reliability by reducing available generation to the grid. Focus should be on Freeze protection measures, not full retrofits/redesign, and should address only those critical components that could potentially trip/derate the unit. Root cause analysis of previous freeze-related outages have not revealed concerns for auxiliary systems that support operation but are considered part of balance-of-plant. These can be addressed through sound operational practices and startup prior to freeze events. In summary, retrofits of existing units should not include all operating systems and should not be required without some cost recovery realized.The SDT should consider ASHRE, a statistically-based standard which uses daily average temperatures, which has been accepted and used by industry for many years. Finally, overdesigned cold weather protection will reduce hot weather reliability. Without practical limit to winter preparation, summer reliability may subsequently be reduced.	
Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	
As an initial matter, we are concerned that the phrase “technical, commercial, or operational constraints” is not sufficiently specific and cannot be interpreted precisely enough to yield incremental reliability benefits. As a generator owner, our view is that all cold weather technical and operational constraints distill down to economic choices. Few, if any, generators are incapable of meeting the proposed standard for technological or operational reasons. The level of investment may vary by technology, and in some cases be significant, but technical and operational constraints can be overcome. Given the significant investment required to ensure a resource can meet the proposed Standards, we would expect a significant number of generators to self-determine that they are exempt from meeting the Standards. As currently worded, compliance with the Standards appear optional. Fundamentally, a Reliability Standard that is supposed to enhance reliability and can be met in almost all cases through investment should not be discriminatory - e.g. old or new resource, class of resource, or optional. This vaguely defined exclusion does not appear to meet this standard. The exemption will also create a patchwork of varying degrees of reliability from generator-to-generator that will make it more difficult for the BAs to manage their grids in extreme conditions. Additionally, the language in §1.4.2 as drafted is unclear as to whether existing generators that have “technical, commercial, or operational constraints” are exempted from the strict requirement of complying with the standard. Specifically, it is unclear whether the “constraints” determination applies to the “timetable” or whether the determination applies to the absolute performance requirement. This language is contrasted with R2 that applies to new generators and is unequivocal in its meaning:	

"Each Generator Owner that is **not able** to implement freeze protection measures for new generating unit(s) as required by Requirement R1 **due to** technical, commercial, or operational constraints as defined by the Generator Owner shall" (emphasis added)

Finally, we think the perceived need for the new generator exemptions belies the overly onerous standard and may be intended for the benefit of a specific resource class. The fact that the drafting team is contemplating an exemption for new generators should provide NERC and stakeholders pause on the reasonableness of the proposed Standards and what exactly the new generator exemption is intending to address.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	Yes
Document Name	

Comment

Capital Power supports the NAGF comments / concerns / suggested revisions in relation to this question.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

Minnesota Power does not believe that freeze protection measures need to be adjusted for its units based on its reliability in past extreme temperatures, however Minnesota Power believes that having an engineering design rated for a 50-year minimum hourly temperature is not feasible, could be extraordinarily costly, and would not improve reliability. It would be difficult to impossible to find an engineer willing to guarantee that these units could operate in -59 Fahrenheit degree temperatures for extended periods of time. Minnesota Power also agrees with NSRF comments recommending to implement a statistical approach similar to NERC to have a more realistic method than identifying the lowest value seen since 1975.

Likes 0	
Dislikes 0	

Response

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	Yes
Document Name	
Comment	
PNM supports EOP-012-1 R1 as long as the language in R1.1 concerning if reliable data is not available back to 1975 an acceptable lesser period is allowed.	
Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1	
Answer	Yes
Document Name	
Comment	
JEA believes that continuous operations at a single recorded temperature will be a significant undertaking (cost, manpower, active maintenance & associated risks) without much benefit in Jacksonville, FL. Our lowest temperature was in 1985 at 7 degrees F for two hours, but our mean low for December, January, and February is 28, 25, and 28 degrees F. To operate for 7 degrees F continually even during the winter season will place a strain on resources, requiring heat tape where insulation would be sufficient (based upon a conservative forecast). Some exclusion for regions that experience minimal freezes should be considered. For example, “If hourly temperature data shows that the entity experienced less than 10 five-hour freezes in the past five years, continuous operation at the minimum temperature is not required.” This is a suggestion, but a suitable expert could be consulted to suggest a time element (X-hour freezes) with a suitable number of cases (Y instances) over a recent time period (past Z years).	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	

Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
TMLP echoes the comments submitted by the Rebecca Baldwin on behalf of TAPS Group for Question 4.	

Likes 0	
Dislikes 0	

Response

Marty Watson - Santee Cooper - 5, Group Name Santee Cooper

Answer	Yes
Document Name	

Comment

First of all upgrading freeze protection design will take several years or more for each unit not currently meeting the Standard. This time period will have to include budgeting for the cost, evaluation by design engineers who may not be available during the implementation period, supply chain issues with everyone in the country buying heat trace hardware and insulating material all at the same time. The second concern is that the cost per Facility could exceed several million dollars. More for large coal units. Third, the design temperature, wind speed and precipitation criteria can't be functionally tested until the weather meets the parameters specified by the design and stays there for an extended period. Untested it could be argued that the unit was in violation of R1 if it has issues at the specified design parameters. Upgrading the design of a Facility to operate continuously at a temperature that may have been reached only one time in fifty years is not acting as a good steward with the money our customers pay for reliable electricity service. We recommend that the implementation plan allow 10 years for compliance with R1.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	Yes
Document Name	

Comment

Xcel Energy has significant concerns with the language in the draft EOP-012 R1 and supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	Yes
Document Name	

Comment

I agree with TAPs comments, pasted below:

We have a number of concerns related to clarity and consistency both within R1, and between R1 and other draft requirements.

"Designed and maintained to be capable of continuous operations"

Our most significant concern is the proposed language in R1.1: "Each generating unit shall be designed and maintained to be capable of continuous operations…." This language is significantly more specific, as well as narrower, than Recommendation 1f, and could result in a GO being found noncompliant with R1 based on an R6 Forced Outage, on the theory that if a unit is "designed and maintained to be capable of continuous operation" at the minimum hourly temperature, then a Forced Outage meeting the criteria of R6 should be impossible. We do not believe that to be the SDT's (or FERC's) intent; R1.1-R1.3 should require GOs to implement freeze protection measures that they reasonably believe will be adequate, which they will supplement and improve pursuant to R6 and R1.4 if an event reveals a shortcoming. We suggest that R1.1 be revised as follows, which parallels the wording of R1.2 and R1.3 but uses the words "based on" to reflect the common understanding of "design basis": "The generating unit design shall be based on the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975." If the SDT does not accept this proposed revision, it should at minimum (1) insert language clarifying that experiencing an R6 event is not evidence that a GO is in violation of R1, and (2) delete the words "and maintain" from R1.1, because maintenance of freeze protection measures is already required by R3.3.

Exceptions from R1.1-R1.3

We believe that the SDT intends that if an existing generator is developing and implementing a CAP pursuant to R1.4, or if an existing or new generator has determined (pursuant to R1.4.4 or R2, respectively) that technical, commercial, or operational constraints prevent it from meeting the criteria in R1.1-R1.3, then the GO will not be found noncompliant with R1.1-R1.3 on the basis of the issue(s) that are being addressed through the CAP or that are prevented by the constraint. But that intention is not expressed in the standard: R1 mandates "freeze protection measures based on" R1.1, R1.2, R1.3, *and* R1.4 as "minimum criteria," in all circumstances. And R1 does not even mention the possibility of *new* generators being unable to meet the criteria, as contemplated by R2. As currently written, a generator availing itself of R1.4 or R2 would be in violation of R1.1-R1.3. We have proposed language below clarifying that applicable generating units must meet the criteria in R1.1-R1.3 *except to the extent that* the GO is developing and implementing a CAP, or has documented technical, commercial, or operational constraints.

New vs. existing generators; combining R2 with R1.4.4

If the standard is to distinguish between "new" and "existing" generators—which we do not believe is necessary—then those terms must be defined for the purpose of this standard. In particular, the SDT would need to clarify two issues: (1) whether a generator's status as "new" or "existing" is fixed permanently based on some set date tied to the effectiveness of the standard (e.g. all generators in service on the state the standard becomes effective are "existing," and all that come online after that point are "new generators" throughout their lifespans), or whether the generator's status is instead determined at the time the standard is being applied (e.g. a generator that discovers the need for additional freeze control measures the day before it is to come online is a "new" generator, and thus must comply with R1.1-R1.3 immediately unless, per R2, a "technical, commercial, or operational constraint" prevents it from doing so, while a generator that makes the same discovery the day after beginning operations is "existing" and must develop and implement a CAP pursuant to R1.4). And (2) for a unit that is under development on the effective date of the standard (or other relevant date), or at the time it discovers the need for additional freeze control measures, at what point in the process of design, permitting, construction, and testing does a generator become "existing" rather than "new"?

It seems that the key difference in the treatment of "new" and "existing" generators in the draft standard is that "existing" generators develop a CAP if their freeze protection measures do not meet the criteria in R1.1-R1.3, and implement the CAP unless prevented by a technical commercial, or operational constraint, while "new" generators must meet the criteria in R1.1-R1.3 unless prevented by a constraint—in short, "new" generators skip the CAP step. This is not, in our view, a distinction that requires the definition of separate classes of generators. A simpler approach would be to revise R1 and merge it with R2 to provide three options for compliance for all generators: (1) if possible, have freeze control measures consistent with R1.1-R1.3; (2) if a generator's freeze control measures are not consistent with R1.1-R1.3, but it is feasible to supplement or modify them to make them consistent, develop and implement a CAP to do so; and (3) if freeze control measures consistent with R1.1-R1.3 are not feasible due to a technical, commercial, or operational constraints, document the constraint and review every five years. Please note that our proposed R1.5 below is based on the text of R2 and R2.1, not R1.4.4; as noted in response to Question 5 below, we suggest that R2.2's five-year review requirement be moved to R4, and thus have not included that subrequirement in our proposed redline of R1.

Lack of deadline in R1.4

Requirement R1.4 requires GOs to develop CAPs in some situations, but provides no deadline by which they must do so. The absence of a deadline places registered entities in the untenable position of having to guess, on a case-by-case basis, how long they have to develop a CAP before they would be deemed noncompliant. The standard should also specify which events trigger the need to develop a CAP pursuant to R1.4, i.e. under which circumstances a generator could need new or modified freeze protection measures. We believe that there are three situations with clear "trigger dates" in which a CAP could be required by R1.4: (1) implementation of this standard, where a generator's existing freeze protection measures do not meet the new criteria; (2) an R6 event, and (3) discovery of the need for changes to freeze protection measures through some other means, including an R4 review that results in either an updated minimum hourly temperature necessitating changes to freeze protection measures, or removal of a previously-documented technical, commercial, or operational constraint. (As explained below, we are suggesting that the CAP elements of R6 be moved to R1.4, leaving only the identification and analysis of the event in R6.) We suggest that CAPs developed when this standard first becomes effective, and in response to an R6 event, use the same deadline as currently proposed in R6: "150 days subsequent to the [event/effective date of this Requirement] or by July 1 that follows the [event/effective date of this Requirement], whichever is earlier." CAPs developed in response to some other means of discovery of the need for changes, including R4 updates, should be developed by July 1 of the year following the calendar year in which the review or other means of discovery takes place. This last class of CAPs should not use the same "by July 1 that follows the [completion of the review]" language as other CAPs, because doing so would force a GO that happened to complete a review or discover an issue in June to develop a CAP in less than a month. And development of such CAPs should have only a date deadline, not an alternative number of days; otherwise, a GO conducting numerous R4 reviews in a calendar year would have an incentive to delay completion of any reviews it thinks likely to result in the need for a CAP, in order to avoid having to develop CAPs at the same time it is continuing its review of other units).

Overlap between R1, R4, and R6

R1, R4, and R6 contain overlapping requirements; for the sake of clarity, and to avoid duplicative noncompliance situations, these overlaps should be eliminated and the relationships between the requirements clarified.

As currently drafted, R1 requires a CAP where a generator "requires either new freeze protection measures or modification of existing freeze protection measures." R4.3 requires each GO to "[r]eview whether its generating units have the freeze protection measures required to operate at the lowest temperature established pursuant to Requirement R1 and, if not, *implement appropriate modifications per the requirements of Part 1.4*." A GO that fails to "implement appropriate modifications per the requirements of Part 1.4" would thus be noncompliant with both R4.3 and R1.4. This issue could be remedied with a minor edit to R4.3: replace "and if not, implement appropriate modifications per the requirements of R1.4" with "If freeze protection measures must be supplemented or modified as a result of the updated lowest temperature, the requirements of Part 1.4 apply."

There is a similar overlap between R1.4 and R6, although R6 does not mention R1.4. R6 requires a GO that has experienced a qualifying event to develop a CAP meeting requirements essentially identical to those of R1.4, with the addition of two analysis requirements ("[a] summary of the identified cause(s) for the equipment freezing event where applicable and any relevant associated data" and "[a] review of applicability to similar equipment at other generating units owned by the Generator Owner"). As drafted, an R6 event would trigger the requirements to develop a CAP pursuant to both R6 and R1.4, unless the R6 analysis identified no need for changes to freeze protection measures. As with the overlap between R1.4 and R4, a failure to develop a CAP would result in an entity being noncompliant with two essentially identical requirements. We suggest replacing R6.2.3 through R6.2.6 with a statement that "Corrective actions in response to an analysis required by R6, including new or modified freeze protection measures, are subject to the requirements of Part 1.4." Language should be added to R1.4 to indicate that it applies to the incorporation of lessons learned pursuant to R6; and the R6.2.3 requirement to identify corrective actions for "identified similar units" can be added to R1.4.1, e.g. "and, if applicable, any similar units identified pursuant to R6.2.2."

Proposed language for R1

Proposed language (clean)

R1. Each Generator Owner shall implement freeze protection measures for each applicable generating unit based on the minimum criteria set forth in R1.1 through R1.3, except to the extent that (i) it is developing and implementing a Corrective Action Plan (CAP) pursuant to R1.4 to enable a unit to meet the criteria set forth in R1.1 through R1.3, or (ii) it has determined, pursuant to R1.5, it is not able to implement freeze protection measures consistent with R1.1 through R1.3 or a CAP developed pursuant to R1.4 due to technical, commercial, or operational constraints: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

1.1. The generating unit design shall be based on the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

1.2. The generating unit design shall account for the cooling effect of wind; and

1.3. {C}The generating unit design shall account for the impacts on operations due to precipitation (e.g., sleet, snow, ice, and freezing rain); or

1.4. {C}For each generating unit whose freeze protection measures require supplementation and/or modification in order to meet the criteria in R1.1 through R1.3, or based on lessons learned pursuant to R6, the Generator Owner shall develop a Corrective Action Plan (CAP) by the deadline determined pursuant to R1.4.2.

1.4.1. The CAP shall include the following at a minimum:

1.4.1.1. An identification of corrective action(s) for the affected unit(s) (and, if applicable, any similar units identified pursuant to R6.1.2), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.4.1.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner; and

1.4.1.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.4.2. The Generator Owner shall develop the CAP according to the applicable deadline from the following:

1.4.2.1. A Generator Owner that determines prior to the effective date of this Requirement that its existing freeze protection measures do not meet the criteria set out in R1.1 through R1.3 shall develop a CAP by no later than 150 days following the effective date of this Requirement, or the July 1 that follows the effective date of this Requirement, whichever is earlier.

1.4.2.2. A Generator Owner that has experienced an event meeting the criteria in R6 shall develop a CAP by no later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier.

1.4.2.3. A Generator Owner that has determined in circumstances other than those described in R1.4.2.1 and R1.4.2.2 that its freeze protection measures require supplementation or modification, including but not necessarily limited to in response to an updated minimum hourly temperature pursuant to Requirement R4.3 or the removal of a technical, commercial, or operational constraint based on a review pursuant to Requirement R4.4, shall develop a CAP by no later than July 1 of the calendar year following the calendar year in which the Requirement R4 review was conducted or the need for the supplementation or modification was otherwise discovered, as applicable.

1.4.3. The Generator Owner shall implement the CAP according to the timetable established pursuant to R1.4.1.2, except to the extent that it is unable to implement the CAP due to a technical, commercial, or operational constraint documented per R1.5.

1.5. Each Generator Owner that is not able to implement (i) freeze protection measures consistent with R1.1 through R1.3 or (ii) a CAP developed pursuant to R1.4 for a generating unit(s) due to technical, commercial, or operational constraints as defined by the Generator Owner shall document its determination and the constraints on implementation.

Alternative Suggestions

Alternative Revisions to R1.4

If the SDT retains R1.4.4 as a subrequirement under R1.4, it should revise R1.4 to state that the CAP must include "the following at a minimum R1.4.1-R1.4.3." R1.4.4 is required only where a GO cannot implement identified corrective actions; it is not a minimum requirement of every CAP.

Alternative Revisions to R1.4.4

If the SDT does not consolidate R2 with R1.4.4 as suggested above, or if it retains the language of R1.4.4 rather than that of R2, it should at minimum eliminate unnecessary inconsistencies between the two requirements, and should delete from R1.4.4 (and from R6.2.6, if that separate subrequirement is retained) the words “that no revisions to the cold weather preparedness plan(s) are required,” which are unnecessary and give the erroneous impression that R1.4.4 applies to situations where no changes are *needed*, as opposed to where changes cannot be made due to constraints. Our suggested revisions to the language of R1.4.4, to the extent that language is retained:

Where deemed appropriate by the Generator Owner, documentation that the Generator Owner is not able to implement some or all of the corrective actions identified pursuant to Parts 1.4.1-1.4.3 due to technical, commercial, or operational constraints as defined by the Generator Owner.

Alternative elimination of duplication between R6 and R1.4

Finally, as also noted in response to Question 10 below, if the SDT retains a separate CAP requirement in R6, it must clarify in R1.4 that corrective actions in response to an R6 event are subject only to R6, not R1.4. Proposed language:

For each generating unit whose freeze protection measures require supplementation and/or modification in order to meet the criteria in R1.1 through R1.3 (except when such supplementation or modification of freeze protection measures is undertaken in response to an R6 event, in which case the CAP requirements of R6 apply)…

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

R1.4.2 establishes a timetable for implementing corrective freeze protection measures actions but the proposed Standard does not establish a implementation period/deadline for the the corrective actions. Recommend that R1.4.2 language be modified to require a reasonable time period/deadline for implementing corrective freeze protection measures.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 6

Answer	Yes
Document Name	

Comment

EOP-012-1 R1 should be modified to allow for an Engineering Analysis to see if units are subjected to potential freezing, with the possibility of eliminating all requirements of the Standard. Temperature alone is not a true indication of freezing, a time component is also necessary to understand

the heat losses. Setting design requirements based on the lowest hourly temperature data places an unecessary burden on southwestern desert facilities that return to above freezing temperatures in a matter of hours. In reviewing the five lowest recorded temperatures since 1975 for IID units, the temperature always returned above freezing the same day. It did not last multiple days or weeks, as in the ERCOT region.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
To retrofit existing units to a historical low temperture below the design temperature should be accompanied with clear cut requirements for an entity to regain the necessary expense for each unit. An IPP does not have the resources vertically integrated utilities have to recoup the required costs or to even front the costs until recovery can be realized. The commercial component of these activities must occur concurrent with the reliability aspects; Heretofore, only the reliability aspects have been identified.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	

Entergy requests clarity around expectation from R1.3.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	

The proposal to require the implementation of new or modified freeze protection measures, as currently drafted, is not sufficiently defined or limited in scope and would propose unreasonable and costly compliance burdens on Generator Owners.

First, the standard should better define "temperature" as used in R1.1--e.g., dry bulb/ambient, wet bulb, dew point, etc.--as well as specify the location at which temperature is to be measured--e.g., plant site versus nearest weather station. Luminant does not have a particular preference on the definition, so long as it is clear what is meant by "temperature."

Second, a more reasonable duration requirement should be set than the proposed single lowest hourly temperature ever recorded since January 1, 1975. The proposed single hour standard does not adequately account for nuances in how resources are impacted by temperature and thus is overly rigid, without a clear reliability benefit. For example, a particular resource may not be impacted by a few minutes or even an hour at a given low temperature, but may face operational issues at a slightly higher temperature for prolonged periods of time (e.g., two or three days of extended low temperatures). For purposes of reliability, extended periods of cold, rather than a few minutes or even an hour at an extreme low temperature, are more concerning and are the circumstances for which Generator Owners should be reasonably prepared. In addition, the proposed single hour standard would impose an unreasonably burdensome, costly, and impractical standard on Generator Owners that is unlikely to produce benefits commensurate with the likely compliance costs. Such costs would be significant, given that retrofitting of units would likely be required to "ensure" (which is not even possible) continuous operation of a resource at the coldest temperature ever to occur for one hour in the past nearly 50 years. Such costs would be especially problematic in a region like ERCOT, where competitive generators have no mechanism for cost recovery (unlike in fully regulated utility regimes). Further, even in ISOs with capacity markets, significant winterization costs could cause a unit to not clear the capacity auction, thus potentially resulting in stranded costs. Significant compliance costs related to weather preparedness and freeze protection could force a resource into early retirement.

In contrast, a requirement to reasonably prepare to operate continuously in the face of prolonged, but more likely cold temperatures is more practical and more likely to improve overall reliability of the grid. One option as an alternative to the proposed lowest hourly standard would be to use a percentile standard, such as the one proposed by the Public Utility Commission of Texas (PUCT) in a pending rulemaking proceeding (currently in the comment phase of the rulemaking process). That rule includes a proposal that generators and transmission operators implement weather emergency preparedness measures that are reasonably expected to ensure sustained operation of the resource at the 95th percentile minimum average 72-hour temperature as reported in a historical weather study published by the Balancing Authority (ERCOT) for the weather zone in which the resource operates. The use of a conservative percentile (95th percentile) and a longer duration (72 hours) better captures likely future cold weather outcomes, rather than focusing on the lowest hourly temperature ever recorded in the past nearly 50 years, which does not represent a likely future temperature or one that would likely be experienced in a future winter for any appreciable amount of time. Further, a 95th percentile/72-hour standard, coupled with the qualification that the requirement is one of reasonable preparedness, is one that Generator Owners could more feasibly meet, at a more reasonable compliance cost, than the SDT's proposed lowest hourly temperature standard.

Alternatively, R1 could be written to conform more closely to the preparedness requirements in R3.4.2, which reference the generating unit's minimum design temperature, historical operating temperature, or current cold weather performance temperature determined by an engineering analysis. Those standards recognize the practicality of the design and performance of a particular resource, rather than imposing an impractical standard based on the coldest temperature recorded since January 1, 1975 (which may significantly pre-date the commercial operation date for a given resource).

Either way, the requirement to implement freeze protection measures or preparedness measures to operate to an exact coldest hourly temperature (with "temperature" undefined) dating back to January 1, 1975 is unduly burdensome, impractical, and unreasonable and should not be adopted.

Finally, in R1.4.2, the timetable for corrective action plans should be revised to provide for the development of a plan in five years, rather than specify a timetable for implementation.

Likes 0	
Dislikes 0	

Response

Mike Braunstein - Colorado Springs Utilities - 1

Answer	Yes
Document Name	

Comment

Colorado Springs Utilities agrees with comments endorsed by LPPC

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation agrees that generating units need to utilize sound practices for cold weather preparation. Constellation suggests eliminating the wording “shall be designed and maintained to be”. Such wording is too prescriptive in how an entity is to ensure cold weather operation, and implies that a unit needs to be “re-designed”. If the intent is to ensure cold weather capability, suggest staying with “Each generating unit shall be capable of continuous operation....” to allow each generating unit to determine the manner in which the capability is to be achieved, depending on the particular circumstances of design, operation, and location of that unit. Also the re-focus on "capable" allows requirement to include generators both existing and new, without use of wording such as "design", allowing a consolidation of the standard (see comments on R2 following.)

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	

Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

The Federal Power Act Section 215 definition of "Reliability Standard" states in relevant part that the term includes requirements for "the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk power system…." This phrase suggests that reliability standards cannot have requirements that require unplanned modifications to facilities. EEI asks the standard drafting team to request the NERC legal department to provide a legal memorandum on whether Section 215 of the Federal Power Act allows a Reliability Standard to require existing generating units to be redesigned or otherwise modified to meet certain freeze protection requirements beyond their original design as set forth in Requirement R1.

Additionally, consideration should be given to the financial impact of the cold weather modifications to existing generating resource owners (GOs) who must balance the benefits of modifying a resource versus retiring it. For this reason and for the overall reliability of the BES, language for Requirement R1, part 1.4.4 should state that the GO is the authority to make such determinations to prevent early retirement of resources which could result in increased pressures on resource adequacy and BES reliability.

EEI does not agree that R1 should specify that generating units must be redesigned to meet certain freeze protection requirements. Instead R1 should require generating units to have the ability to continuously operate within the specified operating ranges. How this is accomplished should be up to the owner.

The wind and precipitation requirements contained in Requirement R1, subparts 1.2 and 1.3 should be combined into subpart 1.1. because as currently written an entity could be faced with multiple violations as a result of their non-compliance for a wind and precipitation violation while any mitigation to address these two issues would be the same.

To address the above issues, we recommend the following revisions to Requirements R1:

R1. Each Generator Owner shall ensure generating units implement freeze protection measures based on the following minimum criteria: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]

1.1 Each generating unit shall be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975, or a lesser period if reliable data is not available to 1975, **and address the cooling effects of wind and precipitation (e.g., sleet, snow, ice and freezing rain)**.

1.2 For each generating unit**s that do not meet part 1.1 above**, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

1.2.1 An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.2.2 A timetable for implementing the corrective action(s) from Part **1.2.1** which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.2.3 An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; and

1.2.4 **In the event a GO is unable to fully mitigate their generating unit to have the continuous operating capability as defined under R1, a determination shall be made**, where deemed appropriate by the Generator Owner based on **their** review of Parts **1.2.1** through **1.2.3**, that no **additional** revisions to the cold weather preparedness plan(s) **will be made** and that no further corrective actions will be taken. The Generator Owner shall document **the** technical, commercial, or operational constraints as defined by the Generator owner as support for such **determination**.

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	

EOP-012-1 is unclear and confusing because of disorganized language and grammatical errors. For example, generating units do not implement anything. Many pieces of equipment do not "freeze," i.e., solid metal is already "frozen" by definition. Rather, equipment fails due to improper protection from extreme cold. The requirements should be stated so that the registered entity, e.g., the Generator Owner, is the one implementing the action. Distinct obligations should be contained in separate requirements, not combined at the requirement part and sub-part levels.

Likes 0	
Dislikes 0	
Response	
Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

Agree with the NAGF comments, but also want to have the SDT consider the following:

For some nuclear plants the temperature band is built into the design and/or licensing basis of the plant. Changing the analysis is not cost effective nor prudent. NERC required temperature bands in excess of what NRC requires for safety of the plant is prohibitive of economic, cost effective operation. Recommend either a statistical approach be taken similar to the NRC to have more realistic numbers than lowest value seen since 1975 or that nuclear is exempt based on extensive design basis analysis that is already done.

One example of an existing nuclear power plant (NPP):

The Updated Safety Analysis Report (USAR) for the NRC states that the NPP is designed for a low temperature of -5F dry bulb which will only be exceeded 1% of the time during the winter. If -5F is exceed a condition report is generated to allow tracking of amount of time the temperature is exceeded. Per the 1972 ASHRAE Handbook of Fundamentals the winter is considered to be December, January, and February for a total of 2160 hrs each year. The design of -5 was taken from the same 1972 ASHRAE Handbook for the location of the NPP which substantiates the statement in the USAR that the design maximum and minimum temperatures will be exceeded approximately 1% of the time during a normal winter. To verify the NPP maintains within this statement a cumulative percentage has been determined for winter months for the period of July 2004 to March 21, 2022. These results show the design low temperature is exceeded only .49% of the time during the winter.

Based on the extensive design analysis performed at the NPP and ongoing trending that occurs each winter to ensure we are bounded by the analysis, it doesn't seem practical to change the entire design/licensing basis of the plant to match the minimum hourly temperature experienced since 1/1/1975

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment

AZPS supports EEI's comments, particularly regarding giving consideration to the financial impact of cold weather modifications vs. retiring a generating unit and that R1 should not specify that generating units must be redesigned to meet certain freeze protection requirements, along with the proposed revisions to R1.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation agrees that generating units need to utilize sound practices for cold weather preparation. Constellation suggests eliminating the wording "shall be designed and maintained to be". Such wording is too prescriptive in how an entity is to ensure cold weather operation, and implies that a unit needs to be "re-designed". If the intent is to ensure cold weather capability, suggest staying with "Each generating unit shall be capable of continuous operation...." to allow each generating unit to determine the manner in which the capability is to be achieved, depending on the particular circumstances of design, operation, and location of that unit. Also the re-focus on "capable" allows requirement to include generators both existing and new, without use of wording such as "design", allowing a consolidation of the standard (see comments on R2 following.)

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

LPPC is concerned that the proposed language in EOP-012-1 R1, as well as Parts 3.1 and 4.1, places significant administrative and analytical burden on entities, and potentially complicates the assessment of design capabilities. LPPC is concerned that collecting and maintaining hourly temperature data would amount to finding a needle in a haystack (over 400,000 data points in a 50 year time period). Instead, LPPC recommends utilizing annual temperature data to identity the lowest temperature recorded for the year. This approach results in a smaller set of data to maintain and is easier for entities to identify the lowest temperature needed for freeze protection. Additionally, analyzing hourly data from summer periods is not beneficial, so a lowest recorded temperature for the year is more appropriate.

LPPC recommends modifying Part 1.1, Part 3.1, and Part 4.1 to remove the requirement for a specific interval, and only require documentation of the lowest recorded temperature since 1975, as follows. These changes allow an Entity to determine whether hourly, daily, or annual is the most appropriate interval for their assessments.

Recommended changes to Parts 1.1, 3.1, and 4.1:

Part 1.1: “Each generating unit shall be designed and maintained to be capable of continuous operations at the lowest recorded ambient temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.”

Part 3.1: “Lowest recorded ambient temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.”

Part 4.1: “Review the lowest recorded ambient temperature developed pursuant to Part 3.1, and update the cold weather preparedness plan with the lowest temperature as necessary.”

These comments have been endorsed by LPPC.

Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	

Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members	
Answer	Yes
Document Name	
Comment	

FMPA does not believe the proposed methodology is an appropriate way to address the the risk presented in recommendation 1f. At heart there are two key issues. First is that while we understand the technical rationale for selecting 1975 as a date to go back to, this is still quite arbitrary and not a very rigorous (statistically) way to ensure we have selected the appropriate level of risk protection. The second issue relates to the first with respect to duration of cold weather. When determining the design requirements for plant equipment to address cold, the temperature, and duration, are equally important. It takes time to freeze. A running plant will withstand most 1hr temperature dips. We do not believe it is appropriate to arbitrarily take the lowest 1 hr (which is really sub-1hr) temperature over the last 47 years and extrapolate that 1 hour duration to “continuous”.

To address both of these issues, a probabilistic-based method should be deployed, which fits the available temperature data to a standard probabilistic distribution and allows the level of extremity of both temperature and duration to be explicitly selected (for example saying the plant must be continuously operable for all temperatures and durations equal to or below “x” standard deviations from the mean). The currently proposed method will result in some areas where plants are weather hardened unnecessarily as well as other areas where the past 47 years of data did not include a temperature as low as, say, the one we get next year. Wind speed should likewise be considered probabilistically. All three of these items should be addressed as part of a methodology that is part of the GO’s cold weather preparedness plan(s). The current proposal implies that plants in south Florida will need to be fully enclosed in a building the way they build plants in North Dakota, because it fails to realize that while South Florida may have seen a brief freezing temperature in the last 47 years, the duration of that freeze is statistically so unlikely to last for 6 hours that modifying plants to address it would be ridiculous.

In addition, this requirement is silent on what data sources will be acceptable (1st order weather station, NOAA, etc) and what constitutes determination that “reliable” data is “not available”. What if no reliable data is available? These issues would need to be resolved when adopting a more rigorous probabilistic methodology.

Likes 0	
Dislikes 0	
Response	
Tom Vinson - American Clean Power Association - 5	
Answer	Yes
Document Name	
Comment	

ACP generally supports R1, but notes this support is conditioned on the retention of the “commercial, technical, or operational constraints” pathway in 1.4.2 and 1.4.4, which constructively addresses a concern ACP raised in comments on the draft standard authorization request (SAR). Without the commercial, technical, or operational constraints pathway, generators could be forced to retire if they do not have a feasible compliance path, which would exacerbate the challenge of generator availability during extreme cold weather. If the commercial, technical, or operational constraints pathway is removed, ACP would oppose R1.

ACP has one concern about this section as currently drafted:

1. In 1.1 the use of the phrase “continuous operations” in the following sentence is problematic for variable energy resources that are dependent on the wind or sun to generate: “Each generating unit shall be designed and maintained to be capable of **continuous** operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.” (emphasis added)

Put simply, wind and solar generation output is variable, not continuous. Therefore, as drafted, GOs of variable generation resources arguably cannot comply. ACP recommends the following redline be adopted (remove the word "continuous" from the sentence):

Each generating unit shall be designed and maintained to be capable of operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975.

Likes 0	
Dislikes 0	
Response	

Michael Dillard - Austin Energy - 5

Answer	Yes
Document Name	

Comment

AE has the following concerns and suggestions:

1. The R1 language may be interpreted as generators having to collect and monitor temperature data within their own premises, as opposed to being allowed to rely on documented temperature data within an identified third party monitored weathter station or recognized weather data source such as NOAA. AE would like to be able to rely on minimum temperature data as recorded from the closet National Weather Service Station (mainly Austin Bergstrom Airport Weather Station). The record minimum temperature data from such NOAA source since 1975 is only available at the daily level. Whether this daily minimum data correlates to hourly minimum temperatures is unknown. In addition, summer temperature data is not necessary and AE’s suggestion would be to only analyse temperature data for the winter months as defined by the BA. In addition, AE would recommend changing the language from hourly minimum temperature to annual minimum temperature in addition to making it clearer that the requirement doesn’t add the burden on entities to collect and monitor hourly temperatures at their own plant facilities and that entities are able to comply by utilizing available third party weather data at a nearby location.
2. R1 and its sub-parts could be read to require continuous operation at the documented minimum hourly temperature, and that if a unit tripped at or above that minimum temperature during an extreme cold weather event, it could be deemed out of compliance. AE believes the SDT’s intent is to require the implementation of freeze protection measures designed with the intent of continuous operation at the documented minimum hourly temperature. R1 states the GO shall ensure generating units implement freeze protection measures, and M1 states each GO will have dated evidence that demonstrates it has freeze protection measures. However, M1 also says “*in accordance with R1*” and R1 part 1.1 says “*Each generating unit shall be designed and maintained to be capable of continuous operations at the documented minimum* ….” AE requests that the SDT clarify the language to ensure the compliance expectation is not continuous operation. No Generator Owner can guarantee its resource will continue to run even if it has implemented the required freeze protection measures.

Likes 0	
Dislikes 0	
Response	

Robert Stevens - CPS Energy - 5	
Answer	Yes
Document Name	
Comment	

Yes, we have concern and want to ensure GO requirements will align with the BA. Using coldest data information since 1975 does have concern, as the GO still won't be able to document all applicable temp/wind/moisture/etc. facts that impact reality. The requirement should only specify the minimum hourly temperature at the nearest National Weather Service location that plant has successfully operated.

Existing generating units should only be required to analyze their designed operation parameters using freeze data and any cold weather limitations based on historic operations dating back to 1975, with defined interval(s) of operation.

Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	

Invenergy has the following concerns and suggestions about the proposed language:

(1) Invenergy supports the retention of the "commercial, technical, or operational constraints" clause in R1, and would be concerned if it were removed.

(2) Invenergy is concerned about the temperature criteria used in R1.1, which relies on an arbitrary historical temperature start date of 1/1/1975 along with a single minimum hourly temperature. Together, these two parameters create an arbitrarily stringent standard that could impose more onerous design and maintenance requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days – that this Standard is intended to address. As but one example, the minimum historical hourly temperature at a given location might be in the middle of the night, but it would not be reasonable to design a solar generator to meet that criterion. Instead, Invenergy suggests the SDT explore alternative methodologies to generate design and maintenance parameters that are targeted to ensuring generator availability during the extreme cold events this Standard seeks to address. For example, and without endorsing the specific parameters used or the resulting proposed requirements, Invenergy notes that the Public Utility Commission of Texas has an open docket (Project No. 53401, Electric Weather Preparedness Standards-Phase II) to set weather preparedness standards. In that proceeding, the Commission Staff proposed (Memorandum and Proposal for Publication dated May 19, 2022), among other items, a standard of "…the lesser of the minimum ambient temperature at which the resource has experience sustained operations or **the 95th percentile minimum average 72-hour temperature** reported in ERCOT's historical weather study…for the weather zone in which the resource is located." (Emphasis added.) The use of a multi-day average temperature with a percentile rather than the single coldest hour better targets the events the Standard is intended to address. The specific parameters (how many hours or days, which percentile, which zones, and other criteria) could be developed as part of the SDT's process.

(3) Invenergy recommends striking “continuous” from R1.1. to be more inclusive of all generation types, such as wind and solar generation output, which is variable, not continuous.

(4) Invenergy suggests the following modifications to R1.4 to clarify Generation Owners declaring a commercial, technical, or operational constraint are not required to develop and implement a Corrective Action Plan:

1.4. For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures to meet the requirements of 1.1, 1.2, or 1.3, the Generator Owner shall do one of the following:

1.4.1. Develop and implement a Corrective Action Plan (CAP) that includes the following at a minimum:

1.4.1.1. An identification of corrective action(s) for the affected unit(s), including any necessary modifications to the Generator Owner’s cold weather preparedness plan(s);

1.4.1.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.4.1.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; **OR**

1.4.2. Submit a declaration that the implementation or modification of freeze protection measures for existing generating unit(s) as required by Requirement R1 is not possible due to technical, commercial, or operational constraints as defined by the Generator Owner, and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	Yes
Document Name	

Comment

Invenergy has the following concerns and suggestions about the proposed language:

(1) Invenergy supports the retention of the “commercial, technical, or operational constraints” clause in R1, and would be concerned if it were removed.

(2) Invenergy is concerned about the temperature criteria used in R1.1, which relies on an arbitrary historical temperature start date of 1/1/1975 along with a single minimum hourly temperature. Together, these two parameters create an arbitrarily stringent standard that could impose more onerous design and maintenance requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days – that this Standard is intended to address. As but one example, the minimum historical hourly temperature at a given location might be in the middle of the night, but it would not be reasonable to design a solar generator to meet that criterion. Instead, Invenergy suggests the SDT explore alternative methodologies to generate design and maintenance parameters that are targeted to ensuring generator availability during the extreme cold events this Standard seeks to address. For example, and without endorsing the specific parameters used or the resulting proposed requirements, Invenergy notes that the Public Utility Commission of Texas has an open docket (Project No. 53401, Electric Weather Preparedness Standards-Phase II) to set weather preparedness standards. In that proceeding, the Commission Staff proposed (Memorandum and Proposal for Publication dated May 19, 2022), among other items, a standard of "…the lesser of the minimum ambient temperature at which the resource has experience sustained operations or **the 95th percentile minimum average 72-hour temperature** reported in ERCOT's historical weather study…for the weather zone in which the resource is located." (Emphasis added.) The use of a multi-day average temperature with a percentile rather than the single coldest hour better targets the events the Standard is intended to address. The specific parameters (how many hours or days, which percentile, which zones, and other criteria) could be developed as part of the SDT's process.

(3) Invenergy recommends striking "continuous" from R1.1. to be more inclusive of all generation types, such as wind and solar generation output, which is variable, not continuous.

(4) Invenergy suggests the following modifications to R1.4 to clarify Generation Owners declaring a commercial, technical, or operational constraint are not required to develop and implement a Corrective Action Plan:

1.4. For each existing generating unit that requires either new freeze protection measures or modification of existing freeze protection measures to meet the requirements of 1.1, 1.2, or 1.3, the Generator Owner shall do one of the following:

1.4.1. Develop and implement a Corrective Action Plan (CAP) that includes the following at a minimum:

1.4.1.1. An identification of corrective action(s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

1.4.1.2. A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

1.4.1.3. An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP; **OR**

1.4.2. Submit a declaration that the implementation or modification of freeze protection measures for existing generating unit(s) as required by Requirement R1 is not possible due to technical, commercial, or operational constraints as defined by the Generator Owner, and that no further corrective actions will be taken. The Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such declaration.

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 3

Answer	Yes
Document Name	

Comment

Yes, we have concern and want to ensure GO requirements will align with the BA. Using coldest data information since 1975 does have concern, as the GO still won't be able to document all applicable temp/wind/moisture/etc. facts that impact reality. The requirement should only specify the minimum hourly temperature at the nearest National Weather Service location that plant has successfully operated.

Existing generating units should only be required to analyze their designed operation parameters using freeze data and any cold weather limitations based on historic operations dating back to 1975, with defined interval(s) of operation.

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP does not agree that R1 should specify that generating units must be redesigned to meet freeze protection requirements. Instead, R1 should require generating units to have the *ability* to continuously operate within an identified operating range, with the methods on how this is accomplished determined solely by the owner. Many actions can and have been taken to ensure units operate successfully through the winter that would not impact unit design (such as temporary enclosures and temporary heat sources).

AEP suggests that R1 be revised so that the wind and precipitation requirements contained in subparts 1.2 and R 1.3 are incorporated into subpart 1.1. The considerations for wind versus precipitation are not always unique and are typically all considered at the same time when systems are reviewed for cold weather operability which is required by R 1.1. As a result, separate sections are not warranted in the standard.

Requirement 1.4.4 allows for the Generator Owner to make a declaration of no action due to technical, commercial, or operational constraints, which infers that the Generator Owner is able to establish the criteria regarding the resulting exemption. AEP agrees with this concept, but suggests that the additional clarity be provided within the standard to make it clear that such a declaration, and the decision making which drives it, is solely at the discretion of the Generator Owner.

AEP supports the comments made by EEI in response to this question.

Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
R1 – 1.1 appears to require us to monitor the temperature at each of our facilities and to review that data from 1/1/1975 to current. Most of our facilities, especially our hydro facilities do not monitor the air temperature or wind speed at our plants. For compliance with EOP 11-2 we intend to use the national weather service at a nearby airport (Spokane) to represent the temperature of the plants in our region. The farthest plant from this datum is about 120 miles from the Spokane airport NOAA station. We believe that the national weather service is a much more credible source of forecasting and monitoring temperatures in our area than our own gauges would be. Does the NERC assume that to comply with EOP 12-2, R1.1 and R3.1 that all plants will now be required to install temperature monitoring at our sites, perform compliance calibrations and certifications on such temperature monitoring equipment, and use our own temperature monitoring equipment at each site to monitor for compliance notification protocols associated with TOP 3-5 and IRO 10-3 to satisfy this standard? If so, this seems unreasonable. To comply with EOP 11-2 our current draft plans for cold weather notifications for EOP 11-2, TOP 3-5 and IRO 10-3 are to use the regional airport temperature from NOAA as our gauge for weather forecasting for all our plants in the area. We have one system operations office that will among many other things, monitor the temperature in the region (if necessary) and perform appropriate callouts to plants proactively, before the temp gets to or below the extreme historical minimum notifying them of extreme cold weather may be on the way at or before the cold weather is experienced at each plant. We believe if we must monitor multiple temperature monitoring sites across our region (at each site, or at a separate datum like regional airports near each plant) we will burden the operations teams with many more activities and calls during a cold weather event. This could lead to many more latent errors, missed steps, completing too many tasks to accurately monitor the operation of the system during an emergency event, and we believe that this would go beyond the intent of the Cold Weather Standard, and/or the report recommendations. Can you please clarify in EOP 12-1 R1.1 and R3.1 if it is acceptable to monitor a regional third-party temperature sensor (Such as NOAA) for compliance with EOP 12-1 for a group of facilities if the temperature monitoring equipment is within 150 miles of each facility?	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the EEI comments and would add that the declarations of technical, commercial, or operational constraints by the GO that limit operational capability should, at minimum, be communicated to their applicable BA and RC to prevent the creation of an avenue for avoidance of availability that would limit the generation being available to the BA during extreme cold weather events.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment

PG&E supports the comments provided by the Edison Electric Institute (EEI) and the North American Generators Forum (NAGF). In addition, PG&E has the following comments:

PG&E representatives attended the April 27th and 28th, 2022 FERC\NERC technical conference on cold weather. Listening to all of the testimony from utilities in New Mexico, Texas, and the South and Eastern United States representing GO's and GOP's, ISO's, and Natural Gas Distributors, it became apparent to PG&E that utilities across the USA have taken corrective actions to harden their generating units from cold weather. PG&E contends that EOP-012-1 is not required and believes that utilities that have had historical operating problems during cold weather events have already implemented cold weather plans/checklists and equipment upgrades that follow the FERC recommendations. EOP-012-1 will make warm-weather utilities perform expensive analysis, training, and design changes that are not commensurate with grid reliability and risk reduction. In the PG&E California portfolio, we have numerous plants that historically have never experienced below-freezing temperatures for extended periods. In addition, numerous GO's in the western part of North America have an extremely low probability of experiencing sub-freezing temperatures. With this new standard, GO's are being required to develop a cold weather plan, train the operating staff, and implement design changes that do not benefit operational reliability or grid reliability. PG&E believes the current EOP-011-1 meets the intent of the FERC recommendations. If EOP-012-1 continues to be developed and later approved, PG&E recommends an allowance (exemption) within the Standard that those GO's who can prove their lowest hourly temperature is above freezing, the Standard should clearly state that those GO's are exempted from EOP-012-1.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3

Answer	Yes
Document Name	

Comment

WEC Energy Group supports EEIs comments.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	Yes

Document Name	
Comment	

EOP-012-1 is unclear and confusing because of disorganized language and grammatical errors, some of which have perpetuated from EOP-011-2. For example, generating units do not implement anything. Many pieces of equipment do not “freeze,” i.e., solid metal is already “frozen” by definition. Rather, equipment fails due to improper protection from extreme cold. The requirements should be stated so that the registered entity, e.g., the Generator Owner, is the one implementing the action. Distinct obligations should be contained in separate requirements, not combined at the requirement part and sub-part levels. Reclamation recommends using active voice throughout the standard to clearly state the requirements.

Reclamation recommends rewriting the requirements of EOP-012-1 as follows:

R1. *use existing language from Draft 1 EOP-012-1 R1.1* with the following corrections:

Each Generator Owner shall design new and maintain existing generating units to be capable of continuous operations at the documented minimum hourly temperature experienced at each unit’s location since 1/1/1975 or a lesser period if reliable data is not available to 1975.

R2. *use existing language from Draft 1 EOP-012-1 R1* with the following corrections:

Each Generator Owner shall implement new or modify existing protection based on the documented minimum hourly temperature for its generating units including the following minimum criteria:

R2.1. the cooling effect of wind; and

R2.2. impacts on equipment operation due to precipitation (e.g., sleet, snow, ice, and freezing rain).

R3. *use existing language from Draft 1 EOP-012-1 R1.4* with the following corrections:

For each existing generating unit that requires new or modified protection based on the documented minimum hourly temperature, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) or, where deemed appropriate by the Generator Owner based on the review of parts R3.1.1 through R3.1.3., declare that no corrective actions will be taken.

R3.1. A CAP shall contain the following minimum information:

R3.1.1. Corrective action(s) for the affected unit(s).

R3.1.2. Any temporary operating limitations that would apply until the corrective actions are implemented.

R3.1.3. A schedule for implementing the corrective action(s).

R3.2. A declaration shall document any technical, commercial, or operational constraints of each affected unit, as defined by the Generator Owner, in support of the declaration.

R4. *use existing language from Draft 1 EOP-012-1 R2* with the following corrections:

Each Generator Owner that does not implement new or modify existing protection based on the documented minimum hourly temperature in accordance with R2 due to technical, commercial, or operational constraints, as defined by the Generator Owner, shall:

R4.1. Document its determination and the constraints; and

R4.2. Review its determination every five calendar years to determine whether the constraints remain applicable.

R5. *use existing language from Draft 1 EOP-012-1 R3*

R6. *use existing language from Draft 1 EOP-012-1 R4, update Part numbers as necessary*

R7. *use existing language from Draft 1 EOP-012-1 R5* with the following corrections:

Each Generator Owner, in conjunction with its Generator Operator, shall ensure generating unit-specific cold weather preparedness plan training is provided to its personnel responsible for implementing cold weather preparedness plans.

R7.1. The Generator Owner and Generator Operator shall identify the entity responsible for providing the training.

R7.2. The Generator Owner and Generator Operator shall ensure the training is provided to personnel responsible for implementing cold weather preparedness plans upon entrance on duty and annually thereafter.

R8. *use existing language from Draft 1 EOP-012-1 R6* with the following corrections:

Each Generator Owner that owns a generating unit that experiences an event resulting in a derate of more than 10% of the total capacity of the unit for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to extreme cold weather effects within the Generator Owner's control to protect against, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall:

R8.1. No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is ***later***, develop a CAP; or

R8.2. Declare, where deemed appropriate by the Generator Owner based on review of Parts 8.3.1. through 8.3.5, that no revisions to the cold weather preparedness plan are required and that no further corrective actions will be taken.

R8.3. At a minimum, a CAP shall contain:

R8.3.1. A summary of the identified cause(s) ***of*** the equipment ***derate, failure to start, or Forced Outage***, and any relevant associated data.

8.3.2 use existing 6.2.1. language

8.3.3. use existing 6.2.2. language

8.3.4. (modified 6.2.3.) Specific corrective action(s) for the affected unit(s) and identified similar units, including:

8.3.4.1. (modified 6.2.3.) any necessary modifications to the Generator Owner's cold weather preparedness plan(s); and

8.3.4.2. (modified 6.2.4.) consideration of any technical, commercial, or operational constraints, as defined by the Generator Owner.

8.3.5. A ***schedule*** for implementing the corrective actions.

R8.4. At a minimum, a declaration shall document technical, commercial, or operational constraints, as defined by the Generator Owner, as support for the declaration.

Reclamation recommends the timeframe for developing a CAP be 150 days subsequent to the event or by July 1 that follows the event, whichever is ***later***. Using whichever is earlier could subject an entity to an unreasonably short deadline depending on when the event occurs.

Reclamation recommends moving the language pertaining to the cold weather preparedness plans from the original R1 to the original R3 (new R5 based on Reclamation's proposed renumbering in the above comments). Modifications to the cold weather preparedness plan should relate back to the CAP, if necessary, not the CAP requirements relating forward to the cold weather preparedness plan.

Reclamation recommends not limiting the training on cold weather preparedness plans to "maintenance or operations" personnel, as other personnel may also be responsible for implementing cold weather preparedness plans and should not be excluded from the training. Reclamation recommends the annual cold weather preparedness plan training be contained in PER-006 instead of EOP-012.

Reclamation supports the retention and reuse of pertinent information from the Draft 1 Measures.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	

"At it's location" may be too ambiguous and doesn't represent enough specificity to accurately define weather conditions. The FERC report also references the nearest city. What constitutes the nearest city? The nearest city may not be indicative of the local weather.

Suggested Edit:

"A NOAA established location within 25 miles. NOAA data is a default. To use another documented method, justification would need to be provided as to why it is needed or why it is superior to NOAA. Alternative temperature data shall be described in the applicable cold weather preparedness plan."

This could also be more detailed in Requirement 3.1 which defines areas that are covered in the cold weather preparedness plan.

Suggest Revising:

R3.1 Documented minimum hourly temperature experienced at a NOAA or Environment and Climate Change (for generating units located in Canada) established location within 25 miles of its location since 1/1/1975 or a lesser period if data is not available.

R3.1.1 Justification for the use of alternative temperature data if NOAA data is unavailable or another source of temperature data is used to determine the minimum temperature

Other concerns are for Commercial Constraints. Will this be interpreted as "too expensive"? Does this clause render the entire Standard moot for anyone that doesn't want to spend the money to upgrade the facilities? Are there any other references in the NERC Standards that allow entities to opt out due to commercial constraints? For example: FAC-003 does not allow for skipping tree trimming due to cost. What will the oversight process be for generators that declare they are unable to implement freeze protection? See ISO—NE Concerns in Question 3.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
DTE Electric supports NAGF comments.Please see NAGF proposed language.	
Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

Concerns include:

1.'Designed and maintained' and 'continuous operation' are not measurable requirements.

Propose this language for R1.1: The generating unit(s) design shall be based on the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

2. R1.4 as written should be separated into multiple Requirements and not part of 1.1 as follows:

2 Each Generator Owner that determines their generating unit(s) require either new freeze protection measures or modification of existing freeze protection measures pursuant to R1, the Generator Owner shall develop and implement a Corrective Action Plan (CAP) which includes the following at a minimum:

2.1 An identification of corrective action (s) for the affected unit(s), including any necessary modifications to the Generator Owner's cold weather preparedness plan(s);

2.1 A timetable for implementing the corrective action(s) from Part 1.4.1 which considers any technical, commercial, or operational constraints, as defined by the Generator Owner;

2.1 An identification of any temporary operating limitations that would apply until execution of the corrective action(s) identified in the CAP

3. If the Generator Owner determines, that no revisions to the cold weather preparedness plan(s) are required and that no further corrective actions will be taken based on the review of Parts 1.1.1 through 1.1.3, the Generator Owner shall document technical, commercial, or operational constraints as defined by the Generator Owner as support for such determination.

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	Yes
Document Name	

Comment

We suggest for the requirement to include cold weather frequency and duration of the criteria to determine if additional cold weather and freeze protection measures need to be implemented. This would allow for generating units in tropical climates that may rarely experience momentary freezing temperatures to more cost effectively implement the standard.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Dominion Energy supports continued cold weather measures being taken for existing generators to meet their designed operating specifications in extreme cold weather. Dominion Energy supports both the EEI and NATF comments that both the FPA Section 215 of 2005 and NERC's own market principles preclude a retrofit requirement for existing generators to meet a design specification universally. The Federal Power Act Section 215 definition of "Reliability Standard" states in relevant part that the term includes requirements for "the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk power system…." This phrase suggests that reliability standards cannot have requirements that require unplanned modifications. Dominion Energy supports EEI's suggestion that the standard drafting team ask NERC to provide a legal memorandum on whether Section 215 of the Federal Power Act allows a Reliability Standard to require existing generating units to be redesigned or otherwise modified to meet certain freeze protection requirements beyond their original design as set forth in Requirement R1.

Additionally, the requirements to make modifications to existing resources to expand their capability may not be a recoverable expense for generator owners.

Additionally, we support two separate requirements, 1) that addresses new generating resources installed on or after the effective date of the Standard and; 2) those generating units that were installed prior to the effective date of the Standard to proactively maintain existing system to ensure the reliable operation of the BES.

R2 for Existing Generating Units installed prior to the effective date of EOP-012-1:

R2. Each Generator Owner **who owns generating units that were placed into commercial operation prior to the effective date of the Standard shall:that is not able to implement freeze protection measures for new generating unit(s) as required by Requirement R1 due to technical, commercial, or operational constraints as defined by the Generator Owner shall:** *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

{C}**2.1.** {C}**Document its determination and the constraints on implementation; and Identify the operational capability of the generating units and supporting auxiliary systems, within the cold weather criteria identified in Requirement R1, subparts 1.1 and 1.2, through one of the following methods:**

2.1.1 Report the designed operational capability as specified by the OEM within the identified cold whether criteria to their responsible GOP and BA; or

2.1.2 Calculate the expected operational capability through either an engineering analysis of available unit data or an assessment of the unit's performance since its commercial operation date, not exceeding a period of twenty years and report it to their responsible GOP and BA. Review its determination every five calendar years to determine whether the documented constraints on implementation remain applicable.

2.2 Report all generating units that are not designed (2.1.1) or do not have the evaluated capability (2.1.2) to reliably operate at their rated capacity over the full range of the cold weather criteria to their responsible GOP and BA.

{C}**2.3 Report the expected cold weather operating capability of each of its generating units to their responsible GOP and BA.**

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy agrees with EEI's comments.

Likes 0	

Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	

NRG has numerous concerns related to this requirement:

A.) NRG agrees with NAGF's comment that the SDT is not following NERC's stated Market Principals, which exist for a reason. NERC needs to address the conflict between the proposed requirement and the Market Principle which states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." By requiring generators to improve their capability to withstand extreme weather beyond the current design, they are requiring expansion of the delivery capability. This proposed requirement also appears to conflict with NERC's Market Principal "A reliability standard shall not give any market participant an unfair competitive advantage." As long as some market participants are able to pass the costs associated with retrofitting units through to rate payers and other market participants are not able to pass the costs through to the end users, the proposal to require retrofits will provide some market participants advantages over others. Has the SDT taken this into account and, if so, how are they addressing the concern?

B). NRG also agrees with the NAGF to support the desire to allow the Transmission Planners, Balancing Authorities, Transmission Operators and Reliability Coordinators to better predict the point where extreme weather may cause problems, but this requirement does not do that. Instead, this requirement puts the onus on generators to be able to operate through any cold weather event, regardless of the existing capability or limits, including potentially more restrictive limits on Transmission, Distribution, and fuel delivery.

C.) NRG generally agrees that, ideally, minimum operating temperatures need to include effects of wind chill and precipitation when defining unit limitations. However, NRG does not agree with using the one-hour min historical operating temperature as the criterion for basing all freeze protection measures for all plant systems. The one-hour criterion is much more conservative, and the probability of this occurring is extremely small yet much more costly to implement. This criterion is not practical and not based upon a technically based industry design standard for freeze protection. The SDT should consider ASHRE, a statistically based standard which uses daily average temperatures, which has been accepted and used by industry for many years. The criterion is also not consistent with other regulatory body rulings such as the PUCT draft ruling (which uses the lesser of the min ambient operation at which the resource has experienced sustained operation or the ASHRE 95% min average 72-hour temp reported in the ERCOT historical study). Finally, overdesigned cold weather protection will reduce hot weather reliability. Without practical limits to winter preparation, summer reliability may subsequently be reduced.

D.) NRG also has concerns that retrofitting existing units to the same design standard as new units will also be costly and lengthy to implement. Focus should be on freeze protection measures, not full retrofits/redesign, and should address only those critical components that could potentially trip/derate the unit. Root cause analyses of previous freeze-related outages have not revealed concerns for auxiliary systems that support operation but are considered part of balance-of-plant. These can be addressed through sound operational practices and startup prior to freeze events. In summary, retrofits of existing units should not include all operating systems and should not be required without some cost recovery realized.

E.) NRG agrees with NAGF's comments that most engineering processes do not attempt to create 100 percent reliability, simply because it is impossible to achieve. This is true for generator design to meet expected temperatures. Traditionally, generation was designed to meet some level of expectation below 100 percent.

For these reasons, NRG cannot recommend support for this requirement until the issues identified here are adequately addressed by the SDT.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment

The cold weather preparedness plan(s) required by EOP-012-1 R3.2 include freeze protection measures be taken. The proposed Requirement R1 appears redundant to R3.2 and should be removed from the proposed revision.

The difference between the temperature requirement in R1.1 and that of the stated minimum unit temperature in R3.4.2 has the potential to be significant and working towards operating at the lowest of the two will possibly, in many cases, be too cost prohibitive and therefore will likely cause many entities to claim this declaration under R1.4.4.

For nuclear plants, the temperature band is built into both the design and licensing basis of the plant. Changing the analysis is neither cost effective nor prudent. The NERC required temperature bands in excess of what NRC requires for safety of the plant is prohibitive of economic, cost effective operation.

As an example, the NRC Updated Safety Analysis Report (USAR) for one particular nuclear plant states that the plant is designed for a low temperature of -5° F dry bulb, which will only be exceeded 1% of the time during the winter. If -5° F is exceed a condition report is generated to allow tracking of the amount of time the temperature is exceeded. Per the 1972 ASHRAE Handbook of Fundamentals, the winter is considered to be December, January, and February, which amounts to 2160 hours each year. The design value of -5° F was taken from the same 1972 ASHRAE Handbook for a location geographically close to the plant, which substantiates the statement in the USAR that the design maximum and minimum temperatures will be exceeded approximately 1% of the time during a normal winter. To verify the operating conditions for this plant meet this statement a cumulative percentage was determined for winter months for the period of July 2004 to March 21, 2022. These results show the design low temperature is exceeded only .49% of the time during the winter.

Based on the extensive design analysis performed at nuclear generating facilities and ongoing trending that occurs each winter to ensure they are bounded by the analysis, it doesn’t seem practical to change the entire design/licensing basis of the plants to match the minimum hourly temperature experienced since 1/1/1975. This proposed NERC requirement is in conflict with the NRC Requirement.

Additionally, the design requirements for line and structure strength are based on wind speeds and radial ice formation less than the historical maximums experienced at the line locations. Construction of a power line designed to withstand the conditions experienced in a hurricane or tornado would be unreasonably cost prohibitive.

Consideration of temperature data back to 1/1/1975 seems excessive and does not correlate to NERC compliance history. We recommend the scope of study required by R1.1 and R3.1 be changed from 1/1/1975 to 6/18/2007. NERC requirements cannot create requirements prior to the enforcement date of June 18, 2007 there is no legal authority.

Recommendation:

a) Change the lookback date for coldest temperature to 6/18/07

b) Implement a standardized statistical approach for all BES generators be taken to have a more realistic method than identifying the lowest value seen since the specified lookback date

c) Include an exemption in Section 4.2 Facilities for nuclear generation based on the extensive design basis analysis that has already been completed

d) Change verbiage of Requirement R1. "Each Generator Owner shall plan to implement freeze protection measures on generating units based on the following minimum criteria: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]"

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA supports the comments submitted by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	

Comment

NRG has several concerns related to this requirement:

A) NRG agrees with NAGF's comment that the SDT is not following NERC's stated Market Principals, which exist for a reason. NERC needs to address the conflict between the proposed requirement and the Market Principle which states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." By requiring generators to improve their capability to withstand extreme weather beyond the current design, they are requiring expansion of the delivery capability. This proposed requirement also appears to conflict with NERC's Market Principal "A reliability standard shall not give any market participant an unfair competitive advantage." As long as some market participants are able to pass the costs associated with retrofitting units through to rate payers and other market participants are not able to pass the costs through to the end users, the proposal to require retrofits will provide some market participants advantages over others. Has the SDT taken this into account and, if so, how are they addressing the concern?

B) NRG also agrees with the NAGF to support the desire to allow the Transmission Planners, Balancing Authorities, Transmission Operators and Reliability Coordinators to better predict the point where extreme weather may cause problems, but this requirement does not do that. Instead, this requirement puts the onus on generators to be able to operate through any cold weather event, regardless of the existing capability or limits, including potentially more restrictive limits on Transmission, Distribution, and fuel delivery.

C) NRG generally agrees that, ideally, minimum operating temperatures need to include effects of wind chill and precipitation when defining unit limitations. However, NRG does not agree with using the one-hour min historical operating temperature as the criterion for basing all freeze protection measures for all plant systems. The one-hour criterion is much more conservative, and the probability of this occurring is extremely small yet much more costly to implement. This criterion is not practical and not based upon a technically based industry design standard for freeze protection. The SDT should consider ASHRE, a statistically based standard which uses daily average temperatures, which has been accepted and used by industry for many years. It is also not consistent with other regulatory bodies rulings such as the PUCT draft ruling (which uses the lesser of the min ambient operation at which the resource has experienced sustained operation or the ASHRE 95% min average 72-hour temp reported in the ERCOT historical study). Finally, overdesigned cold weather protection will reduce hot weather reliability. Without practical limit to winter preparation, summer reliability may subsequently be reduced.

D) NRG also has concerns that retrofitting existing units to the same design standard as new units will also be costly and lengthy to implement. Focus should be on Freeze protection measures, not full retrofits/redesign, and should address only those critical components that could potentially trip/derate the unit. Root cause analysis of previous freeze-related outages have not revealed concerns for auxiliary systems that support operation but are considered part of balance-of-plant. These can be addressed through sound operational practices and startup prior to freeze events. In summary, retrofits of existing units should not include all operating systems and should not be required without some cost recovery realized.

E) NRG agrees with NAGF's comments that most engineering processes do not attempt to create 100 percent reliability, simply because it is impossible to achieve. This is true for generator design to meet expected temperatures. Traditionally, generation was designed to meet some level of expectation below 100 percent.

For these reasons, NRG cannot recommend support for this requirement until the issues identified here are adequately addressed by the SDT.

Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	

Comment	
The year 1975 pre-dates modern weather forecasting and recording capabilities. If desired to extend the monitoring period to that extent, we suggest that the requirement instead specify the minimum hourly temperature at the nearest National Weather Service location. Existing generating units should be required to analyze their designed operation parameters using the freeze protection factors to identify any cold weather limitations based on historic operations dating back to 1975, then develop a time limited Corrective Action Plan. Requirement 1 is an overreach of the Federal Power Act because it requires existing facilities to add equipment or retrofit its facilities.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Installing freeze protection is redundant in many cases and in some case may not even be applicable, not to mention the excessive cost to modify or implement new measures.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
R1 – 1.1 appears to require us to monitor the temperature at each of our facilities and to review that data from 1/1/1975 to current. Most of our facilities, especially our hydro facilities do not monitor the air temperature or wind speed at our plants. For compliance with EOP 11-2 we intend to use the national weather service at a nearby airport (Spokane) to represent the temperature of the plants in our region. The farthest plant from this datum is about 120 miles from the Spokane airport NOAA station. We believe that the national weather service is a much more credible source of forecasting and monitoring temperatures in our area than our own gauges would be. Does the NERC assume that to comply with EOP 12-2, R1.1 and R3.1 that all plants will now be required to install temperature monitoring at our sites, perform compliance calibrations and certifications on such temperature monitoring equipment, and use our own temperature monitoring equipment at each site to monitor for compliance notification protocols associated with TOP 3-5 and IRO 10-3 to satisfy this standard? If so, this seems unreasonable. To comply with EOP 11-2 our current draft plans for cold weather notifications for EOP 11-2, TOP 3-5 and IRO 10-3 are to use the regional airport temperature from NOAA as our gauge for weather forecasting for all our plants in the area. We have one system operations office that will among many other things, monitor the temperature in the region (if necessary)	

and perform appropriate callouts to plants proactively, before the temp gets to or below the extreme historical minimum notifying them of extreme cold weather may be on the way at or before the cold weather is experienced at each plant. We believe if we must monitor multiple temperature monitoring sites across our region (at each site, or at a separate datum like regional airports near each plant) we will burden the operations teams with many more activities and calls during a cold weather event. This could lead to many more latent errors, missed steps, completing too many tasks to accurately monitor the operation of the system during an emergency event, and we believe that this would go beyond the intent of the Cold Weather Standard, and/or the report recommendations. Can you please clarify in EOP 12-1 R1.1 and R3.1 if it is acceptable to monitor a regional third-party temperature sensor (Such as NOAA) for compliance with EOP 12-1 for a group of facilities if the temperature monitoring equipment is within 150 miles of each facility?

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

The proposed language does not provide a formula for determining minimum hourly temperature. Is this minimum instantaneous temperature or integrated minimum temperature over a period of time?

In addition, the new language requires continuous operation but ability to start-up under minimum temperature conditions is left unaddressed or implied. Specific language regarding ability to start-up should be considered for R1.1 in addition to start up failures described in R6.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.	
Likes 0	
Dislikes 0	
Response	
Jun Hua - Austin Energy - 4	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

No Comment.	
Likes 0	
Dislikes 0	
Response	
Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	

NAGF Comments: The NAGF has several concerns related to the requirement.

a. First, the process being used is ignoring, and appears to conflict with, NERC's stated Market Principles. This requirement will most likely cause a depression of prices for energy provided while increasing the cost to own and operate generation. Together, this structure will drive investment out of the generation market at a time when multiple areas of the NERC footprint are seeing concerns with the ability for operators to meet expected load during normal and extreme weather. These issues are why NERC needs to address the conflict between the Market Principle which states "Standards shall not define an adequate amount of, or require expansion of, bulk power system resources or delivery capability." and the proposed requirement. By requiring generators to improve their capability to withstand extreme weather beyond the generator's current design, they are requiring expansion of the delivery capability. This is the same as requiring Transmission Owners or Distribution Providers to harden their wires so no customers will lose power due to a hurricane or tornado. This requirement also appears to conflict with NERC's Market Principle "A reliability standard shall not give any market participant an unfair competitive advantage." As long as some market participants are able to pass the costs associated with retrofitting units through to rate payers and other market participants are not able to pass the costs through to the end users, the proposal to require retrofits will provide some market participants advantages over other market participants in that market.

The NAGF does support the desire to allow the Transmission Planners, Balancing Authorities, Transmission Operators and Reliability Coordinators to better predict the point where extreme weather may cause problems but this requirement does not do that. Instead, this requirement puts the onus on generators to be able to operate through any cold weather event, regardless of the existing capability or limits including potentially more restrictive limits on Transmission, Distribution and fuel delivery.

While the NAGF grants that there are exclusions for the Generator Owner to take, these very exclusions cause the requirement to be completely unenforceable. As written, generator investments to improve or maintain generation may be determined to be too costly by the Generator Owner and therefore no effort need be made beyond writing down that the cost is too much for the benefit expected. With the allowed exceptions, it is even more critical that the BAs, TOPs, TPs and RCs understand each generator's capability and ***use that data in their planning processes***.

b. NERC is moving forward with this requirement to retrofit existing generation without any effort to address Recommendation 2 in the report. If these two recommendations are not addressed together, it is extremely likely that Recommendation 2 will not be addressed until such time as investment in generation has suffered a great deal. Since reports, such as MISO's Summer Readiness, are currently showing a significant potential for insufficient generation in the near future, further retirements and reduced investment in new generation could mean serving loads during most periods of the year will be tight if not impossible. As an example, when concerns already exist related to the retirement of generation causing problems for reliable service, NERC is proposing a requirement to raise the cost of continuous operation with no certainty related to the ability to recoup the costs. In fact, economic theory says that this type of requirement will depress market prices for energy during the winter, making even more generators uneconomic. This requirement will raise the cost to continue to operate the existing fleet of traditional generation, which pushes them to retire even faster.

c. While the requirement mentions both the cooling effect of wind and precipitation, the language does not require any specific identification of impacts to the dry bulb temperature for operational purposes due to wind or precipitation. To the extent a Balancing Authority or Transmission Planner is using a dry bulb temperature to determine if a generator is able to maintain service, then failures to accurately and appropriately forecast seasonal capability will continue to occur. The classic example in this respect is the Polar Vortex of 2014, which caused no trouble in the PJM area (at Allentown, Pa) for a brief (1 hour) dip to of -4.0 F with a wind of 4.6 mph (-14.6 F wind chill) on 1/4/2014, but knocked units offline on 1/7/2014 at sustained conditions reaching 0 F with a 21.9 mph wind (-22.8 F wind chill). How could these units be unreliable at 0 F when they proved themselves able to tolerate -4 F just three days earlier? The answer is that the dry bulb temperature is the wrong parameter, and will always yield wrong expectations, regardless of EOP-012. If a unit is heat-traced for 0 F and a 10 mph wind (-16 F wind chill), for example, is it EOP-012 rated for 0 F, -16 F, or (if the max winter storm wind speed is 30 mph) 7 F (7 F and 30 mph yield a wind chill of -16 F)? The first two alternatives fail to predict outages that will be suffered under blizzard conditions, while the last one is unreasonably pessimistic if applied as a general rule and not solely when a severe windstorm is expected.

d. This requirement also makes no mention of a start-up capability, yet the report authors clearly state that failure to start was an issue. With most generators, a minimum operating temperature is very likely to have no bearing on whether a unit can start at that temperature. A unit's ability to operate at a temperature is not the same thing as a unit's ability to start. Until Balancing Authorities, Transmission Planners, and Transmission Operators utilize the correct information to formulate their plans, they will continue to fail to be adequately prepared. By failing to address startup capability in the standard until a Corrective Action Plan is required (which can be completed by stating that the conditions identified are for continuous operation and not related to startups), the standard is failing to address the critical issue: giving the Balancing Authority and other entities important information about the generator that should be used to appropriately plan system operations.

e. Requirement 1 mentions the cooling effects of wind and precipitation. However, Requirements 3 and 4 and 6 look only at temperature and ignore wind and moisture completely. Each of these requirements must be consistent.

f. Generator Owners are being asked to determine design criteria for weather protection systems for which it is likely impossible to calculate the freeze protection measure. It is true that heat trace applications do have a "design temperature" although experience has shown that this may not be accurately applied from one installation to the next, and likely deteriorates over time. Example of issues with this requirement:

i. what is the design temperature of a wind block for wind coming straight at the structure versus 90 degrees to the left or right?

ii. What is the design temperature (with or without wind) for a temporary enclosure with a portable heater? Is there a significant difference if the source of the heat is electric, kerosene or LP gas? Wind can also blow out flames and carry heat away before it raises the temperature of the system the heater is there to protect.

During FERC's April 2022 technical conference, one panelist stated that it may take several years to determine the point at which a temporary device fails. It is not clear under this requirement what is required to show the design capability. Based on these issues, is it technically feasible to have design documentation for a generator that uses any temporary devices, or does the Generator Owner say that it is technically infeasible to having design documentation until such time as the unit successfully (or unsuccessfully) operates through a severe cold weather event?

g. Most engineering processes do not attempt to create 100 percent reliability. This is true for generator design to meet expected temperatures. Traditionally, generation was designed to meet some level of expectation below 100 percent. Meaning if the expected low temperature was 10 degrees F, the generator design may not have tried to meet that temperature 100 percent of the time. The design would be to have it reliable 97 percent of the time at that point, not have able to operate 100 percent at that point for an undetermined time.

For these reasons, the NAGF cannot recommend support for this requirement until the issues identified here are adequately addressed. The NAGF has provided a revised EOP-012-1 standard for consideration that address these issues in a reasonable manner. Please note that the NAGF cannot recommend its member support a retrofit requirement in any way until such time as the compensation issue is addressed outside of the NERC process as recommended in the report. Until that occurs, the NAGF believe that NERC should focus its efforts on ensuring that ***the planners have and utilize the generator information needed to support improved planning processes***.

Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	EOP-012 Comments - Tenaska Final.docx
Comment	
See comments provided in separate Word documents.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	

Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	

5. The SDT has proposed that owners of new generation that determine that they are not able to implement freeze protection measures due to technical, commercial, or operational constraints review their determination every five years for EOP-012-1 Requirement R2. Is this separate requirement for "new" generation necessary, given that proposed Requirement R4 provides for Generator Owners to perform a similar review every five years to address the ongoing need to review freeze protection measures and historical cold weather temperatures? Please provide any explanation with your response.

Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	No
Document Name	
Comment	
While Oncor is not a Generator Operator or Generator Owner, it does appears that R2 is redundant to R4 and therefore is not necessary.	
Likes 0	
Dislikes 0	
Response	

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
Requirement R4 appears to already fullfill the requirement of R2. The 2 requirements should be merged into one.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
We operate in a cold weather envorpnment, the requirements for our facilities are site specific and are taken into account by the owner. We do not need this language in the standard.	
Likes 0	

Dislikes 0	

Response

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

Answer	No
Document Name	

Comment
Requirement 4 provides sufficient coverage for new generation.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	No
Document Name	

Comment
SEC agrees with R2 as written and does not believe that a requirement for “new” generation is required.

Likes 0	
Dislikes 0	

Response

Israel Perez - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment
We believe that a review of “every six years” is more appropriate as it would align with our audit cycle or be reviewed every other audit.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
R2 seems unnecessary and redundant. This is covered by R1.4.4 and R4.3	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
NRG believes that all new units should be subject to Requirement 1.1(based on criterion stated in Response to 4C), 1.2 and 1.3 for entry into the market and not be eligible for R2. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to more clearly defined. The SDT should consider changing exception for commercial reasons to commercial/economic reasons as requirement that would make a unit uneconomic will result in mothball or retirement of the unit. Exceptions for uneconomic is needed to ensure that standards do not result in greater resource adequacy problems.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
The IESO does not believe a separate requirement is necessary for ‘new generation’, as long as Requirement R4 covers all applicable generating units, and is wide enough in scope and content.	

However, Generator Owners should be required to notify the applicable Balancing Authority of any CAP and its details, or its declaration of not taking corrective action and the technical or operational constraints to support such declaration.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA supports the comments submitted by the US Bureau of Reclamation.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Requirement R2 seems unnecessary when considering Requirements R1.4.4 and R4.3. Neither Requirement R1 nor R4 stipulates the applicable facilities be either new or existing, so any generating plants constructed after the enforcement date of the Standard would be required to comply with R1.4.4 and R4.3. We recommend incorporating Requirement R2 into Requirement R1. Possible solutions are to remove the word, “existing” from the text of R1.4, or to create a new sub-requirement (R1.5.) to account for new generation within the construct of R1.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	No
Document Name	

Comment	
NRG believes that all new units should be subject to Requirement 1.1(based on criterion stated in Response to 4C), 1.2 and 1.3 for entry into the market and not be eligible for R2. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to more clearly defined. The SDT should consider changing the exception for commercial reasons to commercial/economic reasons. If left unclear, the commercial exemption may not apply if following the requirement would not make economic sense, resulting in mothball or retirement of the unit. Exemptions for uneconomic reasons are needed to ensure that this standard does not result in greater resource adequacy problems.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy agrees with EEI's comments. FirstEnergy asks for clarification on when "new" generation would fall under the scope of R1.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the EEI comments and agrees with the SDT that separate requirements are necessary for both new and existing generating units. Dominion Energy is of the opinion that some GOs may not have been sufficiently notified before making commercial commitments for key components, as a result of their approved interconnection agreement, and therefore may not be able to fully comply with the enhanced cold weather requirements similar to GOs with existing generating units. For this reason, we suggest that where GOs who have either begun construction or purchased key components affecting their generating unit's cold weather operational capability and were not properly notified of the enhanced cold weather requirements, should be afforded with a reasonable timeframe (i.e., 5-year reporting cycle) to remediate those issues and in some cases may have long term limitations similar to many existing generating units.	
Likes 0	

Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No
Document Name	

Comment

The SDT should clarify when is a generator considered new and when is it considered existing. In the future, once the Extreme Cold Weather Standards are approved and fully implemented, this distinction will be straightforward, but during the Implementation Period, GO/GOPs will be uncertain what category their generating units fall into.

Likes 1	Los Angeles Department of Water and Power, 3, Skourtas Tony
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	

Comment

DTE Electric supports NAGF comments.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	

Comment

Requirement R4 appears to already fullfill the requirement of R2. The 2 requirements should be merged into one.

Likes 0	
Dislikes 0	

Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends each unit that is unable to have freeze protection measures implemented be reviewed every 5 years on a rolling schedule, regardless of the age of the generating unit.	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
It is felt that this is a duplication of Requirement R2; thus R4 is not needed.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	No
Document Name	
Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4, Group Name NCPA	
Answer	No

Document Name	
Comment	
NCPA agrees with the comments of NRG Energy, Inc.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPCO signed on to ACES comments below: Our answer is based upon not understanding the reason to carve out “new” generation from existing generation. We likely would be supportive of a separate requirement for “new” generation if appropriate justification for it can be provided by the SDT. If the term “new” generation continues to be utilized, we recommend the SDT develop a formal definition for the term.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated. On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made. Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced	

outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
NCPA agrees with the comments of NRG Energy, Inc.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports the EEI comments and believes the GO should be the sole entity to determine technical, operational, or operational constraints that would prohibit compliance from new units.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	

Comment	
We operate in a cold weather envorpnment, the requirements for our facilities are site specific and are taken into account by the owner. We do not need this language in the standard.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
A reference to new generation in this standard will add confusion, because a “new unit” soon becomes “existing generation” after it starts up. In addition, R2 as proposed is duplicative and would be satisfied with minor modifications to consider all units “existing generation.” AEP does not believe this proposed, separate requirement is necessary for “new” generation. In addition, AEP recommends that the five year cycle specified in R2 and R4 be revised to instead be a *maximum* five year cycle, in order to allow the Generator Operator adequate opportunity to align the cycle for all generating assets. AEP supports EEI’s comments in their response to Question #5.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	
No, an additional Requirement appears to be redundant; all GO's should have this requirement.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy agrees that R2, as drafted, is redundant given R1 is applicable to all generating units, and R4 provides for a five year review of cold weather temperatures and freeze protection measures.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy agrees that R2, as drafted, is redundant given R1 is applicable to all generating units, and R4 provides for a five year review of cold weather temperatures and freeze protection measures.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	

Answer	No
Document Name	

Comment

No, an additional Requirement appears to be redundant; all GO's should have this requirement.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	No
Document Name	

Comment

It may be suitable to have parallel requirements for existing and new generators, but the way the draft is written, new generators get a loose, un-enforceable "opt-out" in R2 while existing generators have no such parallel requirement. We see two issues with this. First is that "technical, commercial or operational constraints" is so broad and ambiguous that either no one will have to comply with R1, or everyone will have to, depending on how auditors interpret the requirement. This is unacceptable. Second is that we see no parallel determination of technical, commercial or operational constraints for existing generators (which are far more likely to have these issues than new ones). As far as we can tell in the draft language for existing generators, the only determination is the low one hour temperature experienced at the site since 1975, and whether the unit will run in the "winter season".

As to the question of whether the 5 year review would suffice to cover new generators, we believe any operating generator should have a "determination" on file and the 5 year review is only to re-assess units that already have a determination. So you would need something requiring new units to be evaluated before commercial operation.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Requirement 4 provides sufficient coverage for new generation.

These comments have been endorsed by LPPC.

Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

R2 should be combined with Requirement R1 and extend to any Generator not just new Generators. As written, an entity has to be in violation of R1 to be able to leverage R2 to document its situation. If retained, R2 should be an additional item in R1 where entities either have to meet the specs as set or document the reasons it cannot due to technical, commercial, or operational constraints. R4 should be separately maintained, but should be revised to include periodic review of any determinations that the unit cannot implement the protections due to technical, commercial, or operational constraints.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	

Comment

AZPS supports EEI's comments and proposed revisions to R2.

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Agree with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	No
Document Name	
Comment	
Each unit that is unable to implement protection measures should be reviewed every 5 years, regardless of age or if it is a new or existing resource.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not agree that GOs should be given a separate requirement that allows them to, in perpetuity, have the ability to not meet the freeze protection measures set in EOP-012. Accommodations for generating units that were approved for interconnection, or where key components in the design of the resource were already purchased prior the effective date of EOP-012, should be allowed to make a determination similar to what is provided for existing resources. Otherwise, the generating resource should be designed and constructed to meet the cold weather standards set forth in EOP-012. We suggest the following: **R2.** Each Generator Owner who owns generating units that were placed into commercial operation on or after the effective date of the Standard shall design those units to have freeze protection measures based on the following minimum criteria set forth in Requirement R1, parts 1.1 & 1.2; except where the cold weather criteria contained in parts 1.1 & 1.2 was not conveyed to the owner as a condition of interconnection. In these cases, 2.1 applies. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]	

2.1 The GO shall either modify their new generating unit in compliance with Requirement R1, parts 1.1 & 1.2, and report on their efforts to remediate all issues on a 5 year cycle, or in cases where the generating unit cannot be modified fully for documented technical, commercial, or operational constraints; the GO shall make a determination per Requirement R1, part 1.4.4.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	No
Document Name	

Comment

R2 should be combined with Requirement R1 and extend to any Generator not just new Generators. As written, an entity has to be in violation of R1 to be able to leverage R2 to document its situation. If retained, R2 should be an additional item in R1 where entities either have to meet the specs as set or document the reasons it cannot due to technical, commercial, or operational constraints. R4 should be separately maintained, but should be revised to include periodic review of any determinations that the unit cannot implement the protections due to technical, commercial, or operational constraints.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	

Comment

In five years’ time and in subsequent years, the generator would not be considered new, and Requirement 4 would cover those generators.

Additionally, we believe that allowing an exemption due to commercial constraints as defined by the GO is inconsistent with the concept of mandatory reliability standards. Operational constraints should be supported with a technical basis. All other operational limits are covered in R3. WECC would recommend consideration of replacing “commercial, or operational limitations” with “regulatory constraints.” WECC suggests similar wording changes throughout the standard.

Likes 0	
Dislikes 0	

Response

Mike Braunstein - Colorado Springs Utilities - 1	
Answer	No
Document Name	

Comment

Colorado Springs Utilities agrees with comments endorsed by LPPC

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	

Comment

No. While R4 should be maintained to clarify the review that is required every 5 years with respect to existing weather preparedness plans and freeze protection measures, there is no basis to exclude existing resources from the exceptions in R2, when existing resources are the ones more likely to encounter technical, commercial, or operational impediments to implementing the required freeze protection measures. Thus, R2 should be modified to include existing resources and allow for such resources to determine that they cannot meet the required cold weather preparedness and freeze protection standards for technical, commercial, or operational reasons and to review that determination every 5 years. This is especially important in regions like ERCOT, which has competitive generators that do not currently get any type of guaranteed cost recovery for implementation of freeze protection or weather preparedness standards. Imposing technically, commercially, or operationally infeasible burdens on such Generator Owners may cause or accelerate retirements of existing resources. Therefore, it is important for the standard to acknowledge that technical, commercial, and operational constraints are valid bases for allowing deviations from the draft standard for existing resources, so long as such constraints are documented and reviewed regularly, as proposed in R2.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy	
Answer	No
Document Name	
Comment	
Entergy’s position is R4 encompasses all generation whether it is new or existing, which makes R2 unnecessary.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	No
Document Name	
Comment	
R2 is not necessary. Any new generation is subject to the design requirements of R1 and the review period of R4.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	No
Document Name	
Comment	
Xcel Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	

Answer	No
Document Name	
Comment	
We support LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	No
Document Name	
Comment	
PNM supports having the applicability of EOP-012-1 R4 be applicable to both “new” and “existing” generating units as stated in the comment provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the NAGF comments / concerns / suggested revisions related to this question.	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No

Document Name	
Comment	

We do not agree that a new generator exemption is necessary. We offer that generators, including wind turbines, have been effectively operating in the upper Great Plains, Canada, Sweden, and even Antarctica for many years. If the SDT determines that it is necessary to retain the new generator exemption then we ask that they provide detailed justification why it is necessary.

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 Regional Standards Committee

Answer	No
Document Name	
Comment	

Requirement R4 appears to already fulfill the requirement of R2. The 2 requirements should be merged into one.

Likes 0	
Dislikes 0	
Response	

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE

Answer	No
Document Name	
Comment	

Differentiating between new and existing generation in R2 is not necessary. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to more clearly defined.   The SDT should consider changing exception for commercial reasons to commercial/economic reasons as requirement that would make a unit uneconomic will result in mothball or retirement of the unit. Exceptions for uneconomic is needed to ensure that standards do not result in greater resource adequacy problems.

Likes 0	
Dislikes 0	
Response	

Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	No
Document Name	
Comment	
Agree with ACES comments: Our answer is based upon not understanding the reason to carve out "new" generation from existing generation. We likely would be supportive of a separate requirement for "new" generation if appropriate justification for it can be provided by the SDT. If the term "new" generation continues to be utilized, we recommend the SDT develop a formal definition for the term.	
Likes 0	
Dislikes 0	
Response	

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	No
Document Name	
Comment	
CHPD agrees with LPPC's comments.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #5.	
Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports the MRO NSRF’s comments. Requirement R2 seems unnecessary when considering Requirements R1.4.4 and R4.3. Neither Requirement R1 nor R4 stipulates the applicable facilities be either new or existing, so any generating plants constructed after the enforcement date of the Standard would be required to comply with R1.4.4 and R4.3. We recommend incorporating Requirement R2 into Requirement R1. Possible solutions are to remove the word, “existing” from the text of R1.4, or to create a new sub-requirement (R1.5.) to account for new generation within the construct of R1.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI. Submitted on behalf of Exelon (Segments 1 & 3)	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
Our answer is based upon not understanding the reason to carve out “new” generation from existing generation. We likely would be supportive of a separate requirement for “new” generation if appropriate justification for it can be provided by the SDT. If the term “new” generation continues to be utilized, we recommend the SDT develop a formal definition for the term.	
Likes 0	

Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
SIGE does not believe separate requirements are necessary for new and existing generating units. If R2 stays as is or 'new' is incorporated into R1, SIGE requests the SDT provide a definition of 'new' generation – is this since the effective date of the Standard or does it only apply for a certain amount of time after a unit is online? The definition may impact whether R2 is necessary or if it can be addressed by R1/R4.	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.	
Answer	No
Document Name	
Comment	
Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)	
Likes 0	
Dislikes 0	
Response	
Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
PPL NERC Registered Affiliates generally support EEI comments on Question 5, including proposed language for R1 in the EEI comments. However, consistent with our comments on Question 4, PPL and LG&E and KU offer the following modification to the proposed language for Requirement 2. R2. Each Generator Owner **who owns generating units that were placed into commercial operation on or after the effective date of the Standard shall design those units to have** freeze protection measures based on the minimum criteria set forth in Requirement R1, **parts 1.1 and 1.2 and including cooling effects of wind and freezing precipitation (e.g., sleet, snow, ice, and freezing rain) according to a relevant design**	

standard selected by the GO for the units geographic location except where such cold weather criteria was not conveyed to the owner as a condition of interconnection. In these cases, 2.1 applies.

2.1 **The GO shall either modify their new generating unit in compliance with Requirement R1, parts 1.1 and1.2 and including cooling effects of wind and freezing precipitation (e.g., sleet, snow, ice and freezing rain) according to a relevant design standard selected by the GO for the unit's geographic location, and report on their efforts to remediate all issues on a 5 year cycle, or in cases where the generating unit cannot be modified fully for documented technical, commercial, or operational constraints; the GO shall make a determination per Requirement R1, part 1.2.4.**

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

If R4 applies to all generation, this would include any new generation. Interconnection studies for generation added to the BES should include provisions to meet these standards prior to commercial operations or with detailed schedule for compliance if approved for construction prior to the effective date of these requirements.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller

Answer	No
Document Name	

Comment

NV Energy supports EEIs comments:

EEI does not agree that GOs should be given a separate requirement that allows them to, in perpetuity, have the ability to not meet the freeze protection measures set in EOP-012. Accommodations for generating units that were approved for interconnection, or where key components in the design of the resource were already purchased prior the effective date of EOP-012, should be allowed to make a determination similar to what is provided for existing resources. Otherwise, the generating resource should be designed and constructed to meet the cold weather standards set forth in EOP-012. We suggest the following:

R2. Each Generator Owner who owns generating units that were placed into commercial operation on or after the effective date of the Standard shall design those units to have freeze protection measures based on the following minimum criteria set forth in Requirement R1, parts 1.1, 1.2 & 1.3; except where the cold weather criteria contained in parts 1.1, 1.2 and 1.3 was not conveyed to the owner as a condition of interconnection. In these cases, 2.1 applies. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

2.1 The GO shall either modify their new generating unit in compliance with Requirement R1, parts 1.1, 1.2 and 1.3, and report on their efforts to remediate all issues on a 5 year cycle, or in cases where the generating unit cannot be modified fully for documented technical, commercial, or operational constraints; the GO shall make a determination per Requirement R1, part 1.4.4.

Likes 0	
Dislikes 0	

Response

Hillary Dobson - Colorado Springs Utilities - 3

Answer	No
Document Name	

Comment

CSU supports LPPC's comments.

Likes 0	
Dislikes 0	

Response

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	

Comment

Advise combining the two requirements. In addition, should consider exemption for generation that has proven over decades of cold weather events, i.e., normal weather patterns regularly dip into extended freezing temperatures, that operations are minimally impacted. Performing cold weather contraint analysis periodically for generation units proven to have no problems over many years of operation serves no reliability purpose.

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	
Comment	

It is not necessary to differentiate between new and existing generation in R2. Additionally, this requirement should only apply to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. This is particularly important in regions like ERCOT with competitive generation, where generation owners do not currently have any mechanism for guaranteed cost recovery for implementation of such freeze protection measures. Existing units should also be eligible for exemptions due to technical and operational constraints, as long as these constraints are documented and regularly reviewed. Exemptions due to commercial concerns should be more clearly defined in the draft as they are currently uncelar, though Calpine proposes that the exception for commercial reasons should also be modified to reflect commercial or economic reasons; i.e. a requirement that would make a unit uneconomic such that it will result in mothball or retirement of the unit. Exceptions for economic purposes are needed to ensure that standards do not result in greater resource adequacy problems.

Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	
Comment	

The SRC's recommendation is to continue a periodicity for "all" generating units to review its ongoing freeze protection measures and historical cold weather temperatures; and to provide a cost analysis of any technology that could be employed. Any GO asserting an inability to implement freeze protection measures should be required to perform a periodic review at least every 5 years to demonstrate the constraint is still valid.

Likes 0	
Dislikes 0	
Response	

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5

Answer	No
Document Name	
Comment	

SNPD supports comments submitted by LPPC and Tacoma Power

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

LCRA believes that all new units should be subject to Requirement 1.1 (based on criterion stated in Response to 4C), 1.2 and 1.3 for entry into the market and not be eligible for R2. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to be more clearly defined. The SDT should consider changing the exception for commercial reasons to commercial/economic reasons. If left unclear, the commercial exemption may not apply if following the requirement would not make economic sense, resulting in mothball or retirement of the unit. Exemptions for uneconomic reasons are needed to ensure that this standard does not result in greater resource adequacy problems.

Likes 0	
Dislikes 0	

Response

James Baldwin - Lower Colorado River Authority - 1

Answer	No
Document Name	

Comment

LCRA believes that all new units should be subject to Requirement 1.1(based on criterion stated in Response to 4C), 1.2 and 1.3 for entry into the market and not be eligible for R2. This requirement as written should be considered and applied only to the retrofit of existing units as it may not be economically feasible to retrofit these units to meet the requirements in Requirement 1.1, 1.2 and 1.3. Existing units should be eligible for exemptions due to technical and operational constraints. Exemptions due to commercial concerns are unclear in the draft and need to be more clearly defined. The SDT should consider changing the exception for commercial reasons to commercial/economic reasons. If left unclear, the commercial exemption may not apply if following the requirement would not make economic sense, resulting in mothball or retirement of the unit. Exemptions for uneconomic reasons are needed to ensure that this standard does not result in greater resource adequacy problems.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 5

Answer	No
Document Name	
Comment	
We support LPPC's comments	
Likes 0	
Dislikes 0	
Response	
Ashley Scheelar - TransAlta Corporation - 5	
Answer	No
Document Name	
Comment	
TransAlta supports comments provided by NAGF.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
All exceptions identified by Generator Owners that are submitted to NERC per proposed EOP-012, must be distributed to the applicable BA and TOP. This not only includes the original exception, any subsequent status reports but also the results of the five year reviews. If these units are not expected to be able to generate under specific weather conditions, and the BA and TOP are still expected to provide all necessary electric power, the BA and TOP need to know the status of all resources.	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Redundant information that a 5-year review is acceptable to be included.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Technical reasons may be mitigated over time by development of newer technology or methods. Therefore, a review should occur. The frequency of five years may be too frequent, however. A definition of "new" generation should also be described in R2, and there should be clarification on when R2 does not apply.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment

A declaration that the GO cannot meet the constraints is good, but the Requirement does not specify to whom the declaration must be made. Is it simply a compliance document, or should the requirement specify that the impacted BA(s) be notified of the constraint?

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	Yes
Document Name	

Comment

A definition for New Generating Unit should be provided. As written, I would interpret that R2 would apply to new Generating Units in their first year. After the first year of operation, they will be considered existing Generating units, in which case R1.4 will apply.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	Yes
Document Name	

Comment

Requirement 2 is needed to address the documentation needed to substantiate whether the constraints related to new generating units not able to implement freeze protection measures still exist or apply after a 5 year duration. This particular review of determination is not necessarily addressed in R4.

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

Requirement R4 as currently drafted would not require GOs to review constraints previously documented pursuant to R2 (or R1.4.4 or R6); the separate requirement is therefore necessary. As noted in our response to Question 4, we believe that the distinction between “new” and “existing” generators should be dropped, R1.4.4 deleted, and most of the text of R2 added (with appropriate edits) to R1 as R1.5. R2’s five-year review requirement, however, should instead be moved to R4, as R4.4. Doing so would have two benefits: it would consolidate the five-year reviews in a single Requirement for ease of reference, and it would allow GOs to perform all of their five-year reviews on the same cycle, rather than potentially tracking multiple staggered cycles.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	Yes
Document Name	

Comment

Acciona Energy supports Midwest Reliability Organization’s (MRO) NERC Standards Review Forum’s (NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	Yes

Document Name	
Comment	

R2 should be employeed to capture all “new” generation, however 2.2 can be removed with the utilization of R4. In addition, one needs to be concerned about the inclusion of commercial as a rationale for not completing freeze protection measures for new generators. Does this provide an opportunity on the basis of cost not implement such measures? if so, then the same latitude must be afforded existing units on the basis of cost until such time an adequate FERC compensation strategy is implemented. Therefore, R4 should be further updated to be equivalent to the framework offered by R2.

Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	

Leave R2 as written and add the following to R2: …freeze protection measures for new “ and existing” generating unit(s)…

Likes 0	
Dislikes 0	
Response	

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	Yes
Document Name	
Comment	

I agree with TAPs comments, pasted below:

Requirement R4 as currently drafted would not require GOs to review constraints previously documented pursuant to R2 (or R1.4.4 or R6); the separate requirement is therefore necessary. As noted in our response to Question 4, we believe that the distinction between “new” and “existing” generators should be dropped, R1.4.4 deleted, and most of the text of R2 added (with appropriate edits) to R1 as R1.5. R2’s five-year review requirement, however, should instead be moved to R4, as R4.4. Doing so would have two benefits: it would consolidate the five-year reviews in a single Requirement for ease of reference, and it would allow GOs to perform all of their five-year reviews on the same cycle, rather than potentially tracking multiple staggered cycles.

Likes 0	
Dislikes 0	

Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Requirement R4 as currently drafted would not require GOs to review constraints previously documented pursuant to R2 (or R1.4.4 or R6); the separate requirement is therefore necessary. As noted in our response to Question 4, we believe that the distinction between "new" and "existing" generators should be dropped, R1.4.4 deleted, and most of the text of R2 added (with appropriate edits) to R1 as R1.5. R2's five-year review requirement, however, should instead be moved to R4, as R4.4. Doing so would have two benefits: it would consolidate the five-year reviews in a single Requirement for ease of reference, and it would allow GOs to perform all of their five-year reviews on the same cycle, rather than potentially tracking multiple staggered cycles.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
A separate requirement that recognizes the technical, commercial and operational constraints when implementing new freeze protection measures for a new site is helpful. The process for implementing new freeze protection measures will be different from the process of modifying existing as there is no baseline to correct if it is a new design. This difference can be addressed as a separate requirement for new and existing or another separate subrequirement under R1. Either option can be used to address the different processes for implementation of freeze protection measures. However it is unclear when a new site becomes an existing site. Will there be a date threshold? For example, sites that come online in 2022 are considered new, however, in 2025 are they still to be considered new or do the existing site requirements (R1.4) apply after a certain time.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Q5. ERCOT supports the SRC comments. ERCOT does not believe R2 is necessary because new units would be covered by the general requirement in R1. Also, because developers of units that will come into service after the compliance date of this standard (i.e., 5 years after FERC approval) should have full advance knowledge of the performance requirements, we see no legitimate reason for an exemption from this requirement, unless the impediment arose after the date the generator began operations.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not think a separate requirement for new generation is necessary and has not typically been done in the NERC Reliability Standards. New generation should be subject to the same requirements as existing generation in Requirement R4. If Requirement R2 is upheld, the question would be when the new generation is not considered "new" and when the transition from Requirement R2 to Requirement R4 occurs. Texas RE strongly recommends making clear that new generation shall perform EOP-012-1 R4 prior to the commercial operation date (COD) date as defined in the Registration Policy. Texas RE recommends clarifying when a newly registered entity would be subject to compliance if it is registered during the time period after the effective date of the order, but prior to the compliance date for Requirements R1 and R2. Please see Texas RE's comments to question #9 regarding Requirement R4 periodicity.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	

NAGF Comments: The SDT has not identified what determines a new generator versus an existing generator. Therefore, either the SDT must add information to the requirement to identify these units that qualify as new or treat all units the same, regardless of age. The NAGF recommends that all units be subject to the same requirements, so Requirement 2 is not needed.

The NAGF has provided a revised EOP-012-1standard for consideration that address these issues in a reasonable manner. Please review the proposed changes to the standard.

Likes 0	
Dislikes 0	

Response

Tom Vinson - American Clean Power Association - 5

Answer	
Document Name	

Comment

ACP finds it difficult to respond "yes" or "no" to this question. On the one hand, if R2 is removed, the remaining language would seem to suggest that new generation would be subject to doing a Corrective Action Plan under 1.4 as there would be no distinction between "new" and "existing." On the other hand, it is a bit confusing as originally drafted too in terms of what applies to "new" and what applies to "existing."

As an alternative, ACP recommends relocating R2 under R1 as a new section 1.5. That clarifies there is a single standard for all generation, but establishes separate compliance pathways for new and existing. The SDT could also consider clarifying what is considered "new" and what is considered "existing." Perhaps a resource becomes existing upon the initial 5-year review period.

Likes 0	
Dislikes 0	

Response

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

Jun Hua - Austin Energy - 4	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.	
Likes 0	
Dislikes 0	
Response	

6. The Standard, as proposed, would require Generator Owners to develop plans for modifying generating units to operate to the minimum hourly temperature over the next five years after Commission approval. While Generator Owners identify those generating units that need modifications, develop corrective action plans, and implement modifications, it is important for the ERO Enterprise to have aggregated data about the status of Generation Owners' extreme cold weather preparedness for its generating units for use in its reliability oversight activities.

The SDT believes that there is benefit to having the ERO Enterprise collect information on progress of Generator Owner plans for modifying generating units. The information could be collected through reporting under mandatory Reliability Standard requirements, through a Periodic Data Submittal under Section 400 of the Rules of Procedure (which may or may not be specified in the Compliance section of the standard), or through a request for data under Section 1600 of the Rules of Procedure. Which of these options do you believe is the best procedural option for collecting this information?

Ashley Scheelar - TransAlta Corporation - 5	
Answer	No
Document Name	
Comment	
TransAlta presented in preceding questions that we successfully operate in extreme cold in regions that do not have the type of reliability risk being addressed by this standard. Therefore, there should be no need for data requests. However, if a data request is required it would be best if the entities requesting have the discretion to determine in what regions/generators that information is useful and only request information of those entities. In addition, it is best if a centralized approach is taken as entities like ours operate in many regions and still manage requests and requirements on various platforms and portals which is still very challenging to manage, even with the advent of Align.	
Likes 0	
Dislikes 0	
Response	

John Babik - JEA - 5	
Answer	No
Document Name	
Comment	
We support LPPC's comments	
Likes 0	
Dislikes 0	
Response	

James Baldwin - Lower Colorado River Authority - 1	
Answer	No

Document Name	
Comment	
LCRA suggests GO data is best provided to regional Transmission Planner/Planning Coordinator for aggregation and provided to the ERO who can provide to FERC as desired.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA suggests GO data is best provided to regional Transmission Planner/Planning Coordinator for aggregation and provided to the ERO who can provide to FERC as desired.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Q6. ERCOT supports the SRC comments.	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	

Comment	
Calpine joins the comments of the TCPA and does not have additional comments on this question.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
No is selected to indicate the SDT should avoid data collection for the ERO under a standard requirement unless a defined reliability gap is being addressed. If NERC determines a value in tracking progress of generation unit modification efforts, data collection should be under Section 1600 as developed by NERC, not the SDT. This allows the ERO to modify data collection as necessary, including termination without a standard revision. If compliance monitoring is the objective, then Section 400 is appropriate for requirements meeting reliability objectives.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports EEI's comments. Section 1600 cannot be used to collect entity information on their progress to modify affected generating units because the Rules of Procedure are clear that "Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information." CAPs are compliance obligations clearly defined by EOP-012. For this reason, Section 400 of the Rules of Procedure should be used.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	

Answer	No
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #6.	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	
As we discuss in our response to Q3 we believe that it is more important for the BAs to be active participants in defining the specified operating conditions, defining their need in MWs, and managing the data collection to ensure that their Operating Plans are in mesh with generator cold weather preparedness. Reporting should flow through and by the BAs, not around.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments and would recommend clarification on how this information is going to be used to verify which section of the Rules of Procedure should be referenced.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	

Answer	No
Document Name	
Comment	
We support LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	No
Document Name	
Comment	
Xcel Energy believes Section 400 of the Rules of Procedure is the appropriate avenue to collect this data.	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	No
Document Name	
Comment	
I agree with TAPs comments, pasted below: The information should be collected through a Periodic Data Submittal via the Align tool, which is already being used for other Periodic Data Submittals. It should not be a Reliability Standard requirement.	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	

Answer	No
Document Name	
Comment	

No new data collection process needs to be created by the Standard. Processes currently exist to obtain this data, e.g., Section 1600 data requests, which allow pertinent data to be obtained as deemed necessary by the entities needing the data. Without a confirmed need on the part of the proposed recipient of the data, the usefulness of data gathering and reporting is low.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	No
Document Name	
Comment	

While either of these options are tools at disposal of the ERO entertprise, progress information is not required by any reliability standard. The ERO Enterprise does not collect information on the progress of implementing any other new standards. This type of data collection would be purely administrative and would not improve reliability. Without additional information on how the data would be used beyond an administrative collection tool, it is not clear where the benefit lies.

Likes 0	
Dislikes 0	
Response	

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

Agree with the NAGF comments.

Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
No new data collection process needs to be created by the Standard. Processes currently exist to obtain this data, e.g., Section 1600 data requests, which allow pertinent data to be obtained as deemed necessary by the entities needing the data. Without a confirmed need on the part of the proposed recipient of the data, the usefulness of data gathering and reporting is low. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

This would not apply, based on our review for compliance with EOP 11-2 our plants have operated to conditions as low as experienced in the region (-22 deg F, -38.5 deg F when considering wind chill during that event) and we believe they could operate if the temperature decreased another 10 or 20 degrees. We are already in compliance with this standard so no data submittal for a compliance plan will be required.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 5

Answer	No
Document Name	

Comment

NCPA does not believe there is reason to implement additional reporting requirements and agrees with the comments of NRG Energy, Inc.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4, Group Name NCPA	
Answer	No
Document Name	
Comment	
NCPA does not believe there is reason to implement additional reporting requirements and agrees with the comments of NRG Energy, Inc.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E supports the comments by the North American Generators Forum (NAGF) comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
BHP is supportive of Section 400 or 1600 Reporting as opposed to mandatory reporting through a Reliability Standard Requirement.	

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree there is a benefit to having the ERO Enterprise collect information on progress of Generator Owner plans for modifying generating units. Progress information is not required by any reliability standard. The ERO Enterprise does not collect information on the progress of implementing any other new standards. This type of data collection would be purely administrative and would not improve reliability.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
We support the RSC comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments.	
Likes 0	

Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
This data collection should not be a mandatory Reliability Standard requirement, and would make more sense as a Periodic Data Submittal	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports both EEI and NAGF comments and does not agree that Section 1600 could be used to collect entity information on their progress to modify affected generating units because the Rules of Procedure are clear that “Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information.” CAPs are compliance obligations clearly defined by EOP-012. For this reason, Section 400 of the Rules of Procedure should be used if this information is collected at all. Dominion Energy agrees with the NATF comments that this information being provided to NERC does not add a reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	

NRG agrees with comments made by the NAGF that Generator related capability data based upon progress of modifying units in accordance with implementation plan under Requirement 1.4 would not be as useful for identifying areas of potential concern than data directly from the planning entities, assuming the planning entities are using the information provided by the Generator Owners. This information is best provided by the Generator Owners to the Transmission Planner or Planning Coordinator (who use this info for the necessary planning studies) who can then provide it to the ERO, who can then provide it to FERC as desired. This avoids duplicate and sometimes conflicting information.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports the comments submitted by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
NRG agrees with comments made by the NAGF that Generator related capability data based upon progress of modifying units in accordance with implementation plan under Requirement 1.4 would not be as useful for identifying areas of potential concern than data directly from the planning entities, assuming the planning entities are using the information provided by the Generator Owners. This information is best provided by the Generator Owners to the Transmission Planner or Planning Coordinator (who use this info for the necessary planning studies) who can then provide it to the ERO, who can then provide it to FERC as desired. This avoids duplicate and sometimes conflicting information.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	No
Document Name	

Comment

Section 1600 would be appropriate until ERO could see that CAP efforts are complete.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

SEC does not believe that data requests are necessary. Has the SDT taken into consideration how many entities need to make modifications and the frequency of modification. The standard indicates entities already must have a plan. This would be a burden on the entity and regulatory board reviewing this. SEC believes that the new standard addresses this concern in the requirements.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

This would not apply, based on our review for compliance with EOP 11-2 our plants have operated to conditions as low as experienced in the region (-22 deg F, -38.5 deg F when considering wind chill during that event) and we believe they could operate if the temperature decreased another 10 or 20 degrees. We are already in compliance with this standard so no data submittal for a compliance plan will be required.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	No
Document Name	
Comment	
We are questioning the added value for the specific operating context of some Canadian entities' hydroelectric that have generation units already designed and operated in cold and extreme weather decades ago.	
Likes 0	
Dislikes 0	
Response	
Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	Yes
Document Name	
Comment	
SNPD supports comments submitted by LPPC and Tacoma Power	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
Data requests are the preferred option under Section 1600 Rules of Procedures. Similar to GADS and MIDAS, data submittal dates are scheduled and deadlines are provided to entities in advance and therefore submittal due dates and methods are consistent. In addition, it is important to note that this type of data is not used for compliance evaluation purposes thereby enabling entities to keep their focus on meeting the requirements of the standard.	
Likes 0	
Dislikes 0	
Response	
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.	

Answer	Yes
Document Name	
Comment	
Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)	
Likes 0	
Dislikes 0	
Response	

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC

Answer	Yes
Document Name	
Comment	
Section 400 of the Rules of Procedure	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	
Comment	
Duke Energy suggest the aggregated data be collected through NERC Section 1600 — Request for Data or Information.	
Likes 0	
Dislikes 0	
Response	

Gerry Adamski - Cogentrix Energy Power Management, LLC - 5

Answer	Yes
Document Name	

Comment	
PDS would be the best process for this status update.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	Yes
Document Name	
Comment	
We agree with the collection of data under Section 1600 rather than from a new standard requirement. However, we have some concerns with what is included in the "generating unit" definition, so more clarity is needed to know what is in scope.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	Yes
Document Name	
Comment	

WEC Energy Group supports EEIs comment in favor of Section 400 of the Rules of Procedure.

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	Yes
Document Name	

Comment

ISO-NE has no preference as to the method of reporting, however any Generator cold weather data should be provided to the applicable RCs/BAs/TOPs/PCs/TPs. The EROs already have a method to retrieve periodic data from the BAs under BAL-003. A similar method could be used for the GO cold weather data.

Likes 0	
Dislikes 0	

Response

Mark Young - Tenaska, Inc. - 5

Answer	Yes
Document Name	

Comment

Periodic Data Submittal is the best method.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with EEI's comments and agree with the Data Submittal applying to Section 400 of the Rules of Procedure	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Since both of these rules of procedures are a tool that the ERO can use to see CAP statuses, either is a valuable option for the ERO.	
Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
In addition to the ERO Enterprise collecting information on Generator Owner progress on its plans for modifying generating units, the same information should be provided to their respective Balancing Authorities.	

Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
We agree with the collection of data under Section 1600 rather than from a standard requirement standpoint. However, we share the same concerns from other entities on the equipment included in the “generating unit” as some of the equipment may be in heated facilities or indoors where they may never see those temperatures. So, more clarity is needed to know what is in scope.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Tacoma Power prefers utilizing Section 1600 for data collection, similar to what was implemented for the GMD Standards Project.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	
Document Name	
Comment	

In addition to the ERO Enterprise collecting information on Generator Owner progress on its plans for modifying generating units, the SRC is requesting this same information be provided to Regional Entities, Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Planners, and Transmission Operators. An additional modification to EOP-012-1, along with a form for Generator Owners to populate, may be used similar to how data is collected in BAL-003-2 Frequency Response and Frequency Bias Setting Attachment A, where the ERO is able to collect data from Balancing Authorities on an established periodic basis.

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.

Likes 0	
Dislikes 0	

Response

Jun Hua - Austin Energy - 4

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5

Likes 0	
Dislikes 0	

Response

Hillary Dobson - Colorado Springs Utilities - 3

Answer	
Document Name	

Comment	
Section 1600. CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	
Document Name	
Comment	
NV Energy supports EEI's comments. Section 1600 cannot be used to collect entity information on their progress to modify affected generating units because the Rules of Procedure are clear that "Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information." CAPs are compliance obligations clearly defined by EOP-012. For this reason, Section 400 of the Rules of Procedure should be used.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
We prefer a request for data under Section 1600 of the Rules of Procedure.	
Likes 0	
Dislikes 0	
Response	
Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	

Document Name	
Comment	

PPL and LGE and KU support EEI comments on Question 6.

Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	

Similar to other entities; SIGE would like clarity on what is in scope from a ‘generating unit’ standpoint. Additionally, if a ‘data submittal’ is required, the information is better suited for the Planning Coordinators as it may impact their studies. Their resulting studies could then be provided to the ERO.

Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	
Document Name	
Comment	

Periodic Data Submital under Section 400 of the Rules of Procedures.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1

Answer	
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI. Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	

Response
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	
Document Name	

Comment
CHPD agrees with LPPC's comments.

Likes 0	
Dislikes 0	

Response
Donna Johnson - Oglethorpe Power Corporation - 5

Answer	
Document Name	

Comment
Please explain: Why it is important for the ERO Enterprise to have this information? See additional comments under #7.

Likes 0	
Dislikes 0	

Response
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE

Answer	
Document Name	

Comment

NERC does not need detailed information on progress on the CAP's. Ultimately, the requirements of the EOP-012-1 require development of the CAP and implementing the CAP. The generator owners should be required to provide a timeline for units to be compliant with the RS but not periodic progress reports. An annual statement that the generator owner is on schedule with the CAP should be sufficient for NERC.

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 Regional Standards Committee

Answer	
Document Name	

Comment

RSC abstains from commenting on the best procedural option and trusts that the ERO Enterprise is best suited to make such a determination.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	
Document Name	

Comment

Capital Power supports the NAGF comments / concerns / suggested revisions related to this question. Capital Power encourages NERC to focus on the facilitation of a centralized and consistent data portal for all of the regions (i.e. Align).

Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	
Document Name	

Comment

The information should be collected through a Periodic Data Submittal via the Align tool, which is already being used for other Periodic Data Submittals. It should not be a Reliability Standard requirement.	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	
Document Name	
Comment	
We believe the report should follow Section 1600.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	
Document Name	
Comment	
IID prefers utilizing Section 1600 for data collection.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	
Document Name	
Comment	
Entergy supports data submittal under Section 1600 of the Rules of Procedure.	

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5

Answer	
Document Name	

Comment

Luminant joins the comments of the Texas Competitive Power Advocates (TCPA) and does not have any additional comments on this question.

Likes 0	
Dislikes 0	

Response

Mike Braunstein - Colorado Springs Utilities - 1

Answer	
Document Name	

Comment

Colorado Springs Utilities agrees with comments endorsed by LPPC

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

A yes or no response does not conform to the question contained in Question 6, therefore, EEI has not selected either response. Our response regarding a Section 400 vs. a Section 1600 data request is as provided below:

Section 1600 cannot be used to collect entity information on their progress to modify affected generating units because the Rules of Procedure are clear that "Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information." CAPs are compliance obligations clearly defined by EOP-012. For this reason, Section 400 of the Rules of Procedure should be used.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	
Document Name	
Comment	
AZPS supports EEI's comments that Section 400 of the Rules of Procedure should be used.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	
Document Name	
Comment	
LPPC prefers utilizing Section 1600 of the Rules of Procedure for data collection, similar to what was implemented with the GMD Standards Project, in which FERC simultaneously approved TPL-007-1 and directed the collection of data by way of Section 1600. These comments have been endorsed by LPPC.	
Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	
Document Name	

Comment

FMPA and members support TAPS comments on question 6

Likes 0	
Dislikes 0	

Response

Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

The information should be collected through a Periodic Data Submittal via the Align tool, which is already being used for other Periodic Data Submittals. It should not be a Reliability Standard requirement.

Likes 0	

Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	
Section 1600 would be preferable	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Invenergy believes that a request for data in the ERO Portal under Section 1600 of the Rules of Procedure is the best procedural option for collecting Generator Owner information regarding the modification of its generating units per EOP-012-1 R1.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
Invenergy believes that a request for data in the ERO Portal under Section 1600 of the Rules of Procedure is the preferred procedural option for collecting Generator Owner information regarding the modification of its generating units per EOP-012-1 R1.	
Likes 0	
Dislikes 0	

Response	
Glenn Pressler - CPS Energy - 3	
Answer	
Document Name	
Comment	
We agree with the collection of data under Section 1600 rather than from a new standard requirement. However, we have some concerns with what is included in the "generating unit" definition, so more clarity is needed to know what is in scope.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	
NAGF Comments: The NAGF notes that information related to Generator weather capability should be used by the Transmission Planners, Planning Authorities, Balancing Authorities and Transmission Operators. To the extent that NERC and/or FERC wants information related to an area's expected ability to survive an extreme weather event, the Transmission Planner or Planning Coordinator would be the better entity to provide this information to the ERO who can then provide it to FERC as desired. The NAGF notes that if the planners asked for and utilized information from the generators identifying the pertinent data, this information would be available in the processes already in place. Generator Owner level information is not as useful for identifying areas of potential concern than data directly from the planning entities, assuming the planning entities are using the information provided by the Generator Owners. The NAGF has provided a revised EOP-012-1 standard for consideration that address these issues in a reasonable manner. Please review the proposed changes to the standard.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

AEP believes it would be preferable for this information to be provided outside of NERC data requests, and instead be provided as part of attestations submitted to RTO's in an agreed-upon format and schedule.

If NERC however does choose to make these data requests themselves, we would encourage that those requests not be unduly burdensome on industry in terms of either their detail or frequency. Between the two options suggested, AEP would prefer they be Section 400 requests. In addition, we don't believe Section 1600 data requests would be appropriate in this case, as the ROP states that "the provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information."

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 supports the EEI comments but would like more clarity concerning the proposed methods of submitting information pertaining to EOP-012 and how that data would be collected/reported.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPCO signed on to ACES comments below:

Periodic Data Submital under Section 400 of the Rules of Procedures.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends using Section 1600 of the Rules of Procedure, rather than the Periodic Data Submittal process. This would eliminate possible PNCs from occurring due to Generator Owner engagement in PDS process. This would also provide for a review by Reliability personnel, rather than Compliance personnel.

Likes 0	
Dislikes 0	

Response

Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1

Answer	
Document Name	

Comment

VELCO abstains from commenting on the best procedural option, and trusts that the ERO Enterprise is best suited to make such a determination.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	
Document Name	

Comment

Section 1600

Likes 0	
Dislikes 0	

Response

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

Answer	

Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
N/A. Oncor is not registered as a Generator Owner/Operator.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

No comment on what method is more effective.

Likes 0	
Dislikes 0	

Response

7. The drafting team has developed a proposed data collection framework which could form the basis for a periodic data submittal. If you have any comments or edits to the suggested language, please propose an alternative to address the identified risk during the phased-in compliance period.

Collection framework:

- **The Generator Owner will submit an annual summary table by October 1 of each year to its Regional Entity regarding the status of its generating units (as that term is used in EOP-012-1 4.2 Facilities) having freeze protection measures in accordance with Requirements R1 and R2, along with a nine-year projection of status based on the timetables it has determined for Requirement R1. All projections will be based on the Generator Owner's timetables under Requirement R1.4.2; if timetables are not complete for all units, some MW can be designated as "to be determined." The summary table shall contain:**
    - **Status year (for current year, and future years 1-9);**
    - **Sum of capacities (in MW) of all generating units applicable under Facilities, section 4.2;**
    - **Sum of capacities (MW) of generating units meeting (for current year) and projected to meet (for each of the future years 1-9) the criteria of Requirement R1.1;**
    - **Sum of capacities (MW) of generating units not meeting (for current year) and projected to not meet (for each of the future years 1-9) the criteria of Requirement R1.1;**
    - **Sum of the capacities (MW) of existing generating units declared for no action under Requirement R1 (for current year, and projected for future years 1-9);**
    - **Sum of the capacities (MW) of new generating units identified for no action under Requirement R2 (for current year, and projected for future years 1-9).**

Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
The recording of units forced outage status and derates, will steer existing and new generation owners and operators to weatherize their units and auxillary systems, as it's available capacity will affect the profitability to the units. This incentive is the best driver to see the goal of generation reliability improved.	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
Recommend that this data request cover the listed bullets by primary fuel type to quickly identify trends.	
Likes 0	

Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
No Comments.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
We are questioning the added value of EOP-012 for the specific operating context of some Canadian entites' hydroelectric generating units. For Canadian entites, the necessary cold weather practices are already in place. The administrative burden associated to the tasks being required in the standards outweigh the reliability benefits, as we already have a good handle on planning, operations and maintenance activites in cold (and even extreme cold) weather.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	

Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	
Document Name	

Comment

We are already in compliance with the standard for all of our facilities and will not need to submit a compliance plan.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The final guidance for the periodic data submittal should be inclusive of all generation types. For example, hydroelectric unit capacities are dependent on multiple factors and a unit may not operate to its full nameplate capacity. Based on the above, the guidance should specify whether the “sum of capacities” means the nameplate capacity or an estimate of the available capacity for the upcoming season.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1

Answer	
Document Name	

Comment

This seems duplicative of what entities already send to the RC and regional entity.

Likes 0	

Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Ok with the framework. This may also be added as data collection under Section 1600.	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	
Document Name	
Comment	
VELCO requests that SDT consider whether October 1 provides enough lead time to support the needs of BAs to make necessary preparations for the winter weather season.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	
If this is information the Planning Coordinators and Transmission Planners can use, then NRG would rather submit this information to the PC or TP who could then send it to the Regional Entity. Generator Owners sending additional data to the Regional Entities duplicates work and may cause conflicting information.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
In general, Idaho Power does not believe this level of tracking is needed. Idaho Power proposes an aggregated summary submittal to coincide every five years along with R4. Utilities with prior operating freeze issues should be subject to periodic reporting.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA supports the comments submitted by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
The SDT should not require this granular amount of data and a specific time frame, within this Standard. If this type of information is required, perhaps it can be requested under the construct of question 6. This will allow the RE to determine what highest risk generators that they want to review concerning any CAP progress.	
Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
If this is information the Planning Coordinators and Transmission Planners can use, then NRG would rather submit this information to the PC or TP who could then send it to the Regional Entity. Generator Owners sending additional data to the Regional Entities duplicates work and may cause conflicting information.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy questions why the annual table summary would be to the Regional Entity – in some cases RF- and suggest submitting to **the** BA and not to Regional Entity	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports NAGF comments and does not support this reporting requirement.	
Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
DTE Electric supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	
Document Name	
Comment	
We support the RSC comments. Additionally, We are questioning the added value of EOP-012 for the specific operating context of some Canadian entites' hydroelectric generating units. This is an unnecessary administrative burden for all the generating units, especially Canadian entites' generating units.	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
ISO-NE supports the data collection and requests this information be submitted to the following entities: Regional Entities, Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Planners and Transmission Operators	
Likes 0	
Dislikes 0	
Response	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
Reclamation does not support the proposed data collection. First, its purpose is not identified. Second, any reliability benefit it may provide is not identified. Therefore, it appears to be an additional ask of industry with no purpose and no benefit, which will only serve to detract already limited resources from implementing the newly required activities. Reclamation recommends NERC leverage the existing GADS reporting to satisfy this type of data collection.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
No alternative suggestions. The company would have ‘designed and implemented’ freeze protection measures into new facilities prior to commissioning.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	
Document Name	
Comment	
WEC Energy Group supports EEIs comments.	
Likes 0	
Dislikes 0	

Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends that it would be most useful for the GO to submit its annual summary table to its BA, rather than its Regional Entity since the Regional Entity would not have an action with the data. This would support key recommendation 1g as it would give the BA the status of the generating units and the data could assist with determining the generating unit capacity that can be relied upon forecasted cold weather.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4, Group Name NCPA	
Answer	
Document Name	
Comment	
NCPA does not support collection of this data and agrees with the comments of the U.S. Bureau of Reclamation.	
Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
No comments at this time.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report [The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov)] the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	
NCPA does not support collection of this data and agrees with the comments of the U.S. Bureau of Reclaimation.	
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 supports the EEI comments and would include language to share this information with each generator's applicable BA and RC.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
We are already in compliance with the standard for all of our facilities and will not need to submit a compliance plan.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP does not see a need to include the last bullet for “Sum of the capacities (MW) of new generating units identified for no action under Requirement R2 (for current year, and projected for future years 1-9)”, and recommends that it be deleted from the suggested list. We believe it is duplicative of the fourth bullet which states “Sum of capacities (MW) of generating units not meeting (for current year) and projected to not meet (for each of the future years 1-9) the criteria of Requirement R1.1.”	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
NAGF Comments: Please refer to NAGF’s comments to Questions 3, 4 and 6 above. It is NAGF’s position that this level of information will not be helpful to identify areas of concern for the reasons stated in those responses.	
Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 3	
Answer	
Document Name	
Comment	
This seems duplicative of what entities already send to the RC/BA, recommend RC/BA be required to send to the regional entity. 9-year requirement is too long and should be reduced to 5-year or less. The entirety of Standard EOP-012-1 should have a 5-year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. Further, the scheduling and financing of modifications will require greater than 18 months.	
Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
Invenergy recommends coordinating the scope of the data request with BAs and other regulatory authorities who are making, and have already made, similar requests in order to reduce the administrative burden for Generator Owners.	
Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Invenergy recommends coordinating the scope of the data request with BAs and other regulatory authorities who are making, and have already made, similar requests in order to reduce the administrative burden for Generator Owners.	
Likes 0	

Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	
Document Name	
Comment	

This seems duplicative of what entities already send to the RC/BA, recommend RC/BA be required to send to the regional entity. 9-year requirement is too long and should be reduced to 5-year or less.

The entirety of Standard EOP-012-1 should have a 5-year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. Further, the scheduling and financing of modifications will require greater than 18 months.

Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	

The guidance should specify whether the “sum of capacities” means the nameplate capacity or an estimate of the available capacity for the upcoming season

Likes 0	
Dislikes 0	
Response	
Tom Vinson - American Clean Power Association - 5	
Answer	
Document Name	
Comment	

ACP does not have an objection to the proposed data collection, however, we note that BAs and other regulatory authorities are requesting similar information. ACP recommends coordination and collaboration happen between BAs, EROs, state PUCs etc. who are making similar requests in order to settle on a single set of data that GOs collect on extreme cold weather performance for submission to the various authorities.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	
Document Name	

Comment

This seems convoluted. Entities should not be reporting a 9 year projection, as this is an odd number since planning studies go out to ten years. Some of these quantities don't seem logical as a projection beyond year 1- We see no scenario where we would have a new plant in year 8 that we were projecting to not be able to meet freeze protection requirements. There is no language in R1 that discusses "no action", is it the SDT's intent that there is "no change from the prior year's plan"?

In general, FMPA supports the concept of reporting status but believe the RE should continue to be responsible for Periodic Data Submittals as they deem appropriate based on their forecasted risks.

Likes 0	
Dislikes 0	

Response

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	
Document Name	
Comment	
The final guidance for the data collection (LPPC considers a Section 1600 data request more appropriate), should be inclusive of all generation types. For example, hydroelectric unit capacities are dependent on multiple factors and a unit may not operate to its full nameplate capacity. Based on the above, the guidance should specify whether the “sum of capacities” means the nameplate capacity or an estimate of the available capacity for the upcoming season. These comments have been endorsed by LPPC.	
Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
CEG is concerned that standard based periodic data requests will be difficult to manage over time. The CEG concerns include: any desired changes would require a new standard development project to accomplish; the proposed data has not been vetted with those who might need the data; the data collection inserts a time-table for completion of actions under the Standard that does not appear in the Standard. CEG would instead urge the drafting team to encompass any data requests and collections under the Section 1600 data request process. The Section 1600 data request process is more flexible to update over time as data points or needs change. Such flexibility would allow planning entities across the ERO to tailor the data request as applicable. The Section 1600 Data Request allows for industry comments. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 5	
Answer	
Document Name	
Comment	
AZPS supports the reporting proposal.	
Likes 0	
Dislikes 0	
Response	

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Agree with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley	
Answer	
Document Name	
Comment	
It remains unclear what the benefit of the proposed PDS would offer. Its purpose is not identified. Any reliability benefit it may provide is not identified. Therefore, it appears to be an additional ask of industry with no purpose and no benefit, which will only serve to detract already limited resources from implementing the newly required activities. Other reporting tools, such as GADS, exist to satisfy this type of data collection.	
Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	
EEI supports the reporting proposal as submitted.	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	
Document Name	
Comment	
CEG is concerned that standard based periodic data requests will be difficult to manage over time. The CEG concerns include: any desired changes would require a new standard development project to accomplish; the proposed data has not been vetted with those who might need the data; the data collection inserts a time-table for completion of actions under the Standard that does not appear in the Standard. CEG would instead urge the drafting team to encompass any data requests and collections under the Section 1600 data request process. The Section 1600 data request process is more flexible to update over time as data points or needs change. Such flexibility would allow planning entities across the ERO to tailor the data request as applicable. The Section 1600 Data Request allows for industry comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
Answer	
Document Name	
Comment	
Colorado Springs Utilities agrees with comments endorsed by LPPC	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
If a timetable is specified in R1, Part 1.4.2, it seems that including the phrase "to be determine" is not necessary. WECC offers the following language as an option for consideration. "All projections will be based on the GO's timetable under Requirement R1, Part 1.4.2. If timetables are not finalized for all units, the GO may provide an estimate for completion or list the end date of the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	
Document Name	
Comment	
Luminant has no comments on this question.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	
Document Name	
Comment	
Entergy requests clarification on the definition of capacity. Entergy also recommends a 1-5 year future projection as opposed to 1-9 year. Separating new and existing generating units doesn't add value.	
Likes 0	

Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
Acciona Energy supports Midwest Reliability Organization's (MRO) NERC Standards Review Forum's (NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	
Document Name	
Comment	
But should not be required if the units are exempt from from EOP-012-1 as IID proposes.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy suggest the following modifications: Add the word “existing” to Bullet #1: …table by October 1 of each year to its Regional Entity regarding the status of its “existing” generating units…	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	
Document Name	
Comment	
Xcel Energy supports this reporting proposal.	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	
Document Name	
Comment	
The proposed language is somewhat unclear in its present form. It may be clear enough to comment on if presented in the format of the actual Summary Table.	
Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1	
Answer	
Document Name	
Comment	
We support LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC	
Answer	
Document Name	
Comment	
PNM agrees with the proposed data submittal framework.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power agrees with NSRF's comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	

Answer	
Document Name	
Comment	
Capital Power supports the NAGF comments / concerns / suggested revisions related to this question. Capital Power encourages NERC to focus on the facilitation of a centralized and consistent data portal for all of the regions (i.e. Align).	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	
Document Name	
Comment	
Since R7.2.0 of EOP-011-02 already requires generator owners to define the conditions that they are able to operate under, it seems more informative for the generators to provide the quantity of MWs that are not able to comply with R1.1 and the design conditions that they are expected to be able to operate at. It seems more useful from a planning and progress reporting perspective to report on the shape of the MW vs temperature curves by BA.	
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 Regional Standards Committee	
Answer	
Document Name	
Comment	
We are questioning the added value of EOP-012 for the specific operating context of some Canadian entities' hydroelectric generating units. RSC requests that SDT consider whether October 1 provides enough lead time to support the needs of BAs to make necessary preparations for the winter weather season. This is an unnecessary administrative burden for all the generating units, especially Canadian entities generating units.	

Likes 0	
Dislikes 0	

Response

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE

Answer	
Document Name	

Comment

If this is information the Planning Coordinators and Transmission Planners can use, then TCPA would rather submit this information to the PC or TP who could then send it to the Regional Entity. Generator Owners sending additional data to the Regional Entities duplicates work and may cause conflicting information

Likes 0	
Dislikes 0	

Response

Donna Johnson - Oglethorpe Power Corporation - 5

Answer	
Document Name	

Comment

This submittal does not contribute to the overall reliability of the BES and is an administrative burden on GOs.

Likes 0	
Dislikes 0	

Response

Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County

Answer	
Document Name	

Comment

CHPD agrees with LPPC's comments.

Likes 0	

Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #7.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
MidAmerican believes that a 9-year forecast is too uncertain to be useful; a shorter forecast of no more than 2-5 years seems more appropriate.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI. Submitted on behalf of Exelon (Segments 1 & 3)	
Likes 0	
Dislikes 0	

Response
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	
Document Name	

Comment

No comments at this time.

Likes 0	
Dislikes 0	

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

Answer	
Document Name	

Comment

If this information is to be provided, SIGE has the following comments:

- SIGE interpreted “Regional Entity” to mean Reliability First (for our area). If that is a correct interpretation, SIGE believes this information should not be provided to the “Regional Entity.
- SIGE believes this information is better suited for the Planning Coordinators.
- SIGE would like additional clarity on the ‘capacities’ in the framework – is that nameplate or available capacity for winter season?

Likes 0	
Dislikes 0	

Response
Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	
Document Name	

Comment

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response	
Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates	
Answer	
Document Name	
Comment	
PPL NERC Registered Affiliates support EEI comments on Question 7.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
No Comment.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	
Document Name	
Comment	
NV Energy believes that a 9-year forecast is too uncertain to be useful, a shorter forecast of no more than 2-5 years seems more appropriate.	
Likes 0	
Dislikes 0	
Response	

Hillary Dobson - Colorado Springs Utilities - 3	
Answer	
Document Name	
Comment	
CSU supports LPPC's comments.	
Likes 0	
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	
This fails to address a reliability gap. Suggest this be placed under the Section 1600 process as developed by NERC.	
Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	
Document Name	
Comment	
Portland General Electric Company does not agree with establishing a fixed date for the proposed periodic data submittal. The Regional Entity should retain the flexibility to take of advantage of opportunities to minimize Responsible Entity reporting burdens, through consolidation of this PDS with other existing data requests, such as WECC's annual Loads and Resources data request. Also, the Generator Owner's projection information should also be disseminated to the Generator Owner's BA.	
Likes 0	
Dislikes 0	
Response	

Jun Hua - Austin Energy - 4	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The BA (or the agency with regulatory oversite of the Balancing Authority) should be the entity to determine requirement for submission of information and the content of the same. This will avoid potential duplication and conflict between information already collected by the BA (or applicable oversite authorities) and any new standard.	
Likes 0	
Dislikes 0	
Response	

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC is not a registered Generator Owner or Generator Operator.	
Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	

Comment

The data collection framework proposed is fair, however, the BAs are also requesting this type of information on a regular basis as well as other regulatory entities. Will there be improved coordination between different regulatory entities all requiring similar information?

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	
Document Name	

Comment

The SRC supports this data collection and requests this information to be submitted by the Generator Owners to the Regional Entities, Reliability Coordinators, Balancing Authorities, Planning Coordinators, Transmission Planners and Transmission Operators. Per our response to Question 7, the SRC recommends the addition of this data request via an Attachment to EOP-012-1 to allow for a defined periodic data submittal. The SRC requests the following questions be added to this data request:

Sum of capacities (in MW) by each generating unit

o By units not applicable under Facilities, section 4.2

o By units applicable under Facilities, section 4.2

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Q7. ERCOT supports the SRC comments. ERCOT encourages a thoughtful and efficient process to achieve this awareness.

Likes 0	
Dislikes 0	

Response

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5

Answer	
Document Name	

Comment

SNPD supports comments submitted by LPPC and Tacoma Power

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	
Document Name	

Comment

LCRA suggests this framework is overly burdensome and concerned this type of information is better suited for the regional Transmission Planner/Reliability Coordinator/Balancing Authority. The Regional Entity can inquire with these entities to evaluate risks/issues with implementation on a more global aggregate perspective.

Likes 0	
Dislikes 0	

Response

James Baldwin - Lower Colorado River Authority - 1

Answer	
Document Name	

Comment

LCRA suggests this framework is overly burdensome and concerned this type of information is better suited for the regional Transmission Planner/Reliability Coordinator/Balancing Authority. The Regional Entity can inquire with these entities to evaluate risks/issues with implementation on a more global aggregate perspective.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 5

Answer	
Document Name	

Comment

We support LPPC's comments

Likes 0	
Dislikes 0	

Response

Ashley Scheelar - TransAlta Corporation - 5

Answer	
Document Name	

Comment

These data requirements add to the administrative burden described in previous responses. There should not be any data requirement in regions where there is no reliability risk. However, if a data request is required, it is best if a centralized approach is taken as entities like ours operate in many regions and still manage requests and requirements on various platforms and portals which is still very challenging to manage, even with the advent of Align.

Likes 0	
Dislikes 0	

Response

9. The SDT is proposing an 18-month implementation time frame for all revised and new requirements except EOP-012-1 Requirements R1 and R2 which have a 5-year implementation time frame. Do you agree with this implementation time frame? 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.

Ashley Scheelar - TransAlta Corporation - 5

Answer	No
Document Name	

Comment

TransAlta likely has no need to implement any "new" freeze protection measures due to the fact we operate successfully in extreme cold. However, for generators that have large fleets and many changes to make, this 5-year implementation timeframe is not reasonable for the reasons NAGF and others have raised in their comments.

Likes 0	
Dislikes 0	

Response

James Baldwin - Lower Colorado River Authority - 1

Answer	No
Document Name	

Comment

LCRA suggests a 10 year implementation period is more reasonable and in line with other implemenation periods (i.e. – MOD-026 and MOD-027).

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

LCRA suggests a 10 year implementation period is more reasonable and in line with other implemenation periods (i.e. – MOD-026 and MOD-027).

Likes 0	

Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	
The SRC recommends a twelve month implementation time frame for all revised and new requirements; and a three year implementation time frame for EOP-012-1 Requirements R1 and R2 as this seems to be a sufficient amount of time to become compliant given that the new requirements were included in The Joint Inquiry Report published on November 18, 2021, the additional year for standard development and regulatory review requirements. A twelve month implementation would only miss implementation for one winter (2023-2024).	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
As the standards are drafted, the implementation plan appears very aggressive. This could have the effect of implementing design changes that prove ineffective. Agree with NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	No
Document Name	
Comment	

EOP-011-3 and EOP-012-1 should meet the key recommendations in The Report. Unfortunately, Key Recommendation #2 regarding cost recovery is not addressed. Compliance with EOP-012-1 should be tied to the presence of cost recovery mechanisms in the generator's marketplace. If there is no provision available for cost recovery, compliance with EOP-012-1 should be deferred until a suitable cost recovery mechanism is available to the generator. Further comments on cost recovery from TCPA are contained in our response to Question #10.

Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Capital Power supports the NAGF comments / concerns / suggested revisions related to this question.	
Likes 0	
Dislikes 0	
Response	
Marty Watson - Santee Cooper - 5, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Five year is not enough time to allow for design budgets to be approved, followed by construction budgets and finally implementation of the new designs. Every GO in the nation will be calling on a handful of design engineers, followed by orders for the same heat trace and inulating materials, as well as the limited number of contractors qualified for installation. MOD-026 and MOD-027 were allotted a 10 year implementation period with percentage milestones along the way. Leading up to the first milestone of these Standards there were no conctractors available for more than a year in advance. The same bottleneck will be experienced for EOP-012 but will last longer than a year because multiple disciplines are required during each phase (engineering and construction).. Giving a 10 year implementation will alleviate the bottleneck during subsequent milestones.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	

Answer	No
Document Name	

Comment

A 36-month implementation time frame is suggested for all revised and new requirements except EOP-012-1 Requirements R1 and R2 which should be assigned a 10-year implementation time frame. The basis for these time frames follow:

Requirement R1 will likely require existing sites to retrofit generating units to meet the minimum hourly temperature experienced at the site since 1/1/1975. Although new standards are often implemented 18 months after being accepted or implemented based on fleet completion percentages over several years, R1 will require a detailed engineering analysis to evaluate site conditions to retrofit equipment at each site.

To determine if a component/system must be retrofitted, current design capabilities must be known.   Many older generating sites do not have design basis documentation that provide an in-depth analysis of winter impacts, especially winter impacts for the minimum hourly temperature experienced at the site since 1/1/1975. To implement this requirement, many sites will therefore first have to perform a detailed analysis of all cold weather critical components/systems to determine current winter capability design, followed by an extensive retrofit analysis and implementation. The baseline analysis alone could take several years to perform for older units and likely involve extensive contractor support. As stated, the above descibed work would challenge a site's ability to meet any normal implementation methods commonly used by NERC.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	No
Document Name	

Comment

An 18 month implementation will not allow enough time for a large fleet to ensure all units are compliant, to complete required analysis, design change and schedule vendor/contractor resources. Implementation schedule could reflect fleet size, for example 5 years for a large fleet. For comparison, MOD-026 and MOD-027 had a 10 year implementation period. MOD-025, PRC-019 and PRC-024 all had 5 year implementation periods. The proposed requirement that could require every unit to upgrade their capability will require a great deal more resources and manpower than any of these other standards.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	No
Document Name	
Comment	

The implementation period stated in the plan for EOP-012-1 R1-R2 is 42 months, not the above stated 60 months. There should also be consideration that EOP-011-2 is not yet even effective, resulting in ineffective use of resources associated with the planning and adjustments required to satisfy moving compliance requirements.

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

Agree with the NAGF comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	
Comment	

An 18 month implementation will not allow enough time for a large fleet to ensure all units are compliant, to complete required analysis, design change and schedule vendor/contractor resources. Implementation schedule could reflect fleet size, for example 5 years for a large fleet. For comparison, MOD-026 and MOD-027 had a 10 year implementation period. MOD-025, PRC-019 and PRC-024 all had 5 year implementation periods. The proposed requirement that could require every unit to upgrade their capability will require a great deal more resources and manpower than any of these other standards.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6

Likes 0	

Dislikes 0	
Response	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members	
Answer	No
Document Name	
Comment	
FMPA does not believe the time frames to be reasonable based on the unfavorable language and technical basis of the standards as presented. FMPA and members additionally support TAPS comments on question 9	
Likes 0	
Dislikes 0	
Response	
Robert Stevens - CPS Energy - 5	
Answer	No
Document Name	
Comment	
The entirety of Standard EOP-012-1 should have a 5-year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. GO engineering analysis, development, planning, outage scheduling, etc. require greater than 18 months.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 3	
Answer	No
Document Name	
Comment	

The entirety of Standard EOP-012-1 should have a 5-year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. GO engineering analysis, development, planning, outage scheduling, etc. require greater than 18 months.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
NCPA agrees with the comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	No
Document Name	

Comment

NCPA agrees with the comments of the MRO NSRF provided in their extended comments on question 10.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E supports the comments provided by the North American Generators Forum (NAGF).	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends a 24-month implementation plan. Once again, modifications are being proposed to standards that are not even effective yet. This environment of constant churn results in ineffective use of resources associated with the planning and adjustments required to satisfy moving compliance requirements. NERC should foster a compliance environment that allows entities to fully implement technical compliance with current standards before moving to subsequent versions.	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Alliant Energy supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	

The prior implementation plan for EOP-011-2 included the passing of 2 winter seasons (2021-2022 and 2022-2023) before becoming effective. Adding another 18 months after approval, which is expected in the fall, could include two additional winters beyond the original effective date.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
The 5 years implementation timeframe may be arbitrarily chosen; i.e. there is no correlation between the number of the generating units requiring compliance measures implementation and the implementation timeframe. Timeframe for implementation should be subject on the outage coordination process and the negotiation between the GO/GOP and BA and should be mutually agreed by both GO/GOP and BA.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE Electric supports NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports the proposed 18 month implementation for all revised and new requirements for EOP-011-3 and EOP-012-1 (except R1 & R2) but disagree with the proposal to only allow 42 months after the implementation of EOP-012-1 for Requirements R1 and R2. Instead, we ask for the full 60 months after the implementation of EOP-012-1 for R1 & R2 in order to ensure fulfillment of the requirements.

Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
Document Name	
Comment	
It is unclear if the implementation plan is for full compliance of R1/R2 requirements or if the 5-year requirements is to develop a CAP and not to retrofit existing units. This needs to be clarified by the SDT. Retrofits of existing units to the proposed standard requirements under R1 and R2 will require considerable time to implement based upon outage and resource constraints to perform freeze protection hardening as well as budgetary considerations. A 5-year horizon is not consistent with other new standards that have allowed for 10 or 12 years to implement, such as MOD-026 and MOD-027 as well as PRC-005, that are tied with outages to schedule and implement. NRG believes that this should be extended to a 10-year window.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The Implementation Plan, Effective Date and Phased-in Compliance Dates section, states the implementation period for EOP-012-1 Requirement R1 and R2 is 42 months. The time required for physical implementation of material modifications to generating plants could be highly variable depending on the extent of the modifications. For example, installation of heat trace on a few components at a small single unit station would likely take significantly less time than more major modifications to a large coal unit, which would ostensibly occur more quickly than changes to a nuclear unit. NSRF recommends at least a 10-year implementation period for these requirements, or consideration of a staggered approach to the implementation period based on the type of plant and required modifications. A staggered approach seems to have the potential to be exceedingly complicated.	
Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh

Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA supports the comments submitted by the US Bureau of Reclamation.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
This is unclear if the implementation plan is for full compliance of R1 /R2 requirements or if the 5-year requirements is to develop a CAP and not to retrofit existing units. This needs to be clarified by the SDT. Retrofits of existing units to the proposed standard requirements under R1 and R2 will require considerable time to implement based upon outage and resource constraints to perform freeze protection hardening as well as budgetary considerations. A 5-year horizon is not consistent with other new standards that have allowed for 10 or 12 years to implement, such as MOD-026 and MOD-027 as well as PRC-005, that are tied with outages to schedule and implement. NRG believes that this should be extended to a 10-year window.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
The entirety of Standard EOP-012-1 should have a 5 year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. Further, the scheduling and financing of modifications will require greater than 18 months.	

Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
The implementation timeframe is fair including 5 years for R1 and R2 and 18 months for the other requirements.	
Likes 0	
Dislikes 0	
Response	
Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Calpine agrees with a 5-year implementation time frame to develop a corrective action plan under R1 and R2, though the SDT should be clarified to specify whether the proposed timeline is for full compliance of R1 /R2 reqirements or to develop a corrective action plan. Retrofits of existing units to the proposed standard requirements under R1 and R2 will require considerable time to implement based upon outage and resource constraints and based on budgetary considerations; therefore, a 5-year timeline for such implementation is not reasonable and is inconsistent other new standards that have allowed for 10 or 12 years to implement, such as MOD-026 and MOD-027 as well as PRC-005.	
Likes 0	
Dislikes 0	
Response	
Hillary Dobson - Colorado Springs Utilities - 3	
Answer	Yes
Document Name	
Comment	
CSU supports LPPC's comments.	

Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

PPL NERC Registered Affiliates support EEI comments on Question 9.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	Yes
Document Name	

Comment

Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	

Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MidAmerican supports EEI's comments. We support the proposed 18-month implementation for all revised and new requirements for EOP-011-3 and EOP-012-1 (except R1 & R2) but disagree with the proposal to only allow 42 months after the implementation of EOP-012-1 for Requirements R1 and R2. Instead, we ask for the full 60 months after the implementation of EOP-012-1 for R1 & R2.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #9.	
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 Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
The 5 years implementation timeframe may be arbitrarily chosen; i.e. there is no correlation between the number of the generating units requiring compliance measures implementation and the implementation timeframe. Timeframe for implementation should be subject to the outage coordination process and the negotiation between the GO/GOP and BA and should be mutually agreed upon by both GO/GOP and BA	

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

Minnesota Power agrees with NSRF comments that R1.1 has the potential to cause entities to incur significant costs and therefore allow entities to either declare exemption through R1.4.4 or decommission generating units. Minnesota Power also agrees that the declaration of exemption based on commercial constraints as stated in R1.4.4 would not increase performance, and the decommissioning of units may have the unintended consequence of decreasing the resiliency of the grid by removing sufficient capacity from the market. Minnesota Power believes that the Criteria in R6 is an effective approach to investigate issues experienced during the cold to continuously improve reliability.

Likes 0	
Dislikes 0	

Response

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC

Answer	Yes
Document Name	

Comment

PNM agrees with the proposed 18-month implementation timeline with exception of EOP-012-1 R1 and R2 which are 5-years.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	Yes
Document Name	

Comment

Xcel Energy supports the implementation plan as proposed.	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
No Comments.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Would like to see flexibility with the 5-year implementation plan. Given the current state of the economy and the supply chain disruptions, industry wide contractor and supply issues could impact a 5-year implementation.	
Likes 0	
Dislikes 0	
Response	
Dan Roethemeyer - Vistra Energy - 5	
Answer	Yes
Document Name	
Comment	

Luminant agrees with the general implementation timeline, but notes that it appears the implementation plan specifies a 42 month implementation plan for EOP-012-1, R1, R2 versus a 5-year (i.e. 60 month) implementation time frame above. The implementation plan document should be changed to 60 months.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

EEI supports the implementation plan as proposed.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment

AZPS supports the implementation plan as proposed.

Likes 0	
Dislikes 0	

Response

Tom Vinson - American Clean Power Association - 5

Answer	Yes
Document Name	

Comment

ACP supports the proposed implementation time frames, including five years for R1 and R2 and 18 months for other items.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Invenergy agrees with the proposed implementation time frames.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP agrees with a 5-year implementation timeframe for EOP-012-1 Requirements R1 and R2 (as suggested by Question #9), we do not believe this is clearly articulated within the proposed Implementation Plan. EOP-012-1 R1 and R2's implementation period start date appears to be the same as the start date for the other requirements rather than being subsequent to them. We believe clarity is needed within the Implementation Plan to make it clear that EOP-012-1 Requirements R1 and R2 indeed has a 5-year implementation time frame.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company supports the EEI comments that the timeframes are reasonable.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3

Answer	Yes
Document Name	

Comment

WEC Energy Group supports EEIs comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

BHP feels the 18 month implementation, baring any supply chain issues for entities; but the 5 years is sufficient.

Likes 0	
Dislikes 0	

Response

Brian Evans-Mongeon - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Did the SDT intend for R1 and R2 to have a 5-year implementation time frame? In other words, giving GOs up to five years to fully implement a CAP if needed? If so, we agree this is a reasonable time frame considering budget planning for capital expenses and potential supply chain issues.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Implemetation timeframes should as short as can be feasibly implemented.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
The implementation Plan states: “Entities shall not be required to comply with Requirement R1 and R2 until 42 months after the effective date of Reliability Standard EOP-012-1.” This is confusing and should just state 60 months.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	

Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Depending on the final drafting of the Standard and associated guidance for CAPs, Tacoma Power supports an 18-month implementation timeframe.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro sees no issues with these standards, or equipment that is designed for the extremes of our local environment. Any deviation should be addressed in a timely manner.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Watt - Oklahoma Municipal Power Authority - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Gerry Adamski - Cogentrix Energy Power Management, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Braunstein - Colorado Springs Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Foung Mua, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; Wei Shao, Sacramento Municipal Utility District, 3, 5, 6, 4, 1; - Tim Kelley, Group Name LPPC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Skourtas - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
Q9. ERCOT supports the SRC comments regarding the implementation timing.	
Likes 0	
Dislikes 0	
Response	

Jun Hua - Austin Energy - 4	
Answer	
Document Name	
Comment	
I support comments made by Michael Dillard, Austin Energy, Segment 5	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	
Document Name	
Comment	
NV Energy supports EEI's comments. We support the proposed 18-month implementation for all revised and new requirements for EOP-011-3 and EOP-012-1 (except R1 & R2) but disagree with the proposal to only allow 42 months after the implementation of EOP-012-1 for Requirements R1 and R2. Instead, we ask for the full 60 months after the implementation of EOP-012-1 for R1 & R2.	
Likes 0	
Dislikes 0	
Response	
Mark Spencer - LS Power Development, LLC - 5	
Answer	
Document Name	
Comment	
As drafted, the proposed standards may require invasive modifications to existing facilities that may only reasonably be performed during a major inspection (for combustion turbines) or major outages (for steam turbine). Our experience is that these outage cycles may be 8 years or longer and require significant pre-planning given that the new systems may need to be designed, equipment procured, and installed. While most facilities may be able to comply with R1 and R2 within the 5 year timeframe, some will not without scheduling a dedicated outage. We suggest that if generators are able to demonstrate that if the obligations cannot be accomplished within a scheduled outage within the 5-year window that they be granted a one-time extension of up to 10 years.	
Likes 0	

Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	
Document Name	
Comment	

TMLP echoes the same concerns raised by TAPS Group:

TAPS had understood that the intent was for R2 and R4 (not R1) to have 5-year implementation periods, because both involve five-year reviews. If the SDT's intent is to give R1 a 5-year implementation period, and R4 an 18-month period, we would appreciate more information regarding the SDT's reasoning.

Likes 0	
Dislikes 0	
Response	
Lisa Martin - Austin Energy - 6	
Answer	
Document Name	
Comment	

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

TAPS had understood that the intent was for R2 and R4 (not R1) to have 5-year implementation periods, because both involve five-year reviews. If the SDT's intent is to give R1 a 5-year implementation period, and R4 an 18-month period, we would appreciate more information regarding the SDT's reasoning.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

NAGF Comments: MOD-026 and MOD-027 had a 10 year implementation period. MOD-025, PRC-019 and PRC-024 all had 5 year implementation periods. The proposed requirement to require every unit to upgrade their capability will require a great deal more resources and manpower than any of these other standards. Additionally, there are a limited number of qualified sources to provide the required Engineering and Design Analysis Services. An implementation time period for Requirement 1 of less than 10 years is unreasonable.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends clarifying the implementation plan. Texas RE strongly recommends including an initial performance date for Requirement R4 in the implementation plan. When there is no initial performance data specified for periodic requirements, it is a challenge to determine when the entity needs to perform the action(s) for the first time. In the past, when there is no initial performance date specified, the entity would not have to be compliant until the effective date plus the amount of the periodicity. In this case, 18 months after first day of first calendar quarter after the effective date of the Order plus five years. Is this the SDT’s intent? With regards to Requirement R2, the implementation plan does specify a compliance date. Is that intended to be an initial performance date of R2.2? The terms compliance date and initial performance date should be clarified. Please see Texas RE’s comments in question #5 regarding Requirement R2.

Texas RE does think a CAP could be developed in less than 42 months.

Texas RE recommends that entities have a one-year periodicity in Requirement R4, rather than five years. Texas RE is concerned a new issue may arise, such as a new minimum temperature/condition occurs that affects the units, in less than five years.

Texas RE recommends the retention cover the entire period, whether it is five years or one year. The retention period should consistent with the period in the requirement.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

AECI and its members support comments provided by ACES.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

NA

Likes 0	
Dislikes 0	

Response

10. Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

(1) For EPO-012 R1, R3 includes different areas that can cause Generation to be unavailable.

3.4.1.1. Capability and availability;

3.4.1.2. Fuel supply and inventory concerns;

3.4.1.3. Fuel switching capabilities; and

3.4.1.4. Environmental constraints.

Manitoba Hydro suggests that an additional area could be considered which details the switchgear to be rated for the area weather conditions in that area, back to 1975's coldest temperature. The scope of equipment being the GOP's switchgear, from the unit, to where it meets the TOP's switchgear and/or the BES.

Manitoba Hydro regularly operates in extreme cold weather conditions, in addition to cooling water and DIW systems being at risk to extreme cold; Breakers and Disconnects are common points of failure in cold weather conditions.

Proposed addition to 3.4.1 Generating unit(s) operating limitations in cold weather to include:

3.4.1.5. Switchgear connecting the unit to the BES.

(2) Question 8 was not visible in this online comment form. Manitoba Hydro's response is as follows:

Question 8. The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.

YES

Comments: Manitoba Hydro agrees, while the scope of cost is not available to the SDT at this time, the improvements being recommended are reasonable.

Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	

Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Gul Khan	
Answer	
Document Name	
Comment	
Oncor agrees that the proposed modifications to EOP-011-3 meet the applicable key recommendations from the report in a cost effective manner.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	
For Canadian entites, operation of hydroelectric generating units in cold weather condition is part of the normal operating conditions. The design, maintenance and operation of the generating units are done accordingly. For example, the generating units being installed indoor (either in a powerhouse or underground), they do not require specific freezing measure protection. Consider removing the Time Horizon and VRF columns in the EOP-011-3 VSL Table. Requirement R3 in EOP-012-1 reads that "each GO shall implement and maintain one or more cold weather preparedness plans …" where as R5 refers to "implementing cold weather preparedness plans developed pursuant to R3.". The SDT should consider revising R3 to include "develop, implement and maintain one or more cold weather preparedness plans".	
Likes 0	

Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI and its members support comments provided by ACES.	
Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	
Introduction, Section 4.2 - Please modify the definition of “Facilities” to include only “Thermal Generating Facilities - facilities that use a fuel source such as hydrocarbons, human or other derived trash, and/or facilities that use the heating and/or cooling of water to generate electricity”. Thermal generating facilities as defined above appear to be the primary intended target of this standard and are the most susceptible facilities for extreme cold weather. The standard specifically calls out things for us to assess for each facility such as “Fuel Switching Capability,” “Fuel Supply and Inventory Concerns” and “Environmental Concerns” (i.e., Environmental Permitting Concerns). Preliminary review of this standard in accordance with EOP-11-2 for our Hydro Generating facilities has not identified any significant impact to the operation of our facilities, maintenance practices, or limitations on operation due to temperature. An ongoing review of our hydro facilities every five years for fuel switching capabilities, fuel supply and inventory concerns, and environmental permitting concerns, design temperature concerns, etc. for our hydro facilities will be an ongoing paperwork exercise and does not seem to align with the intent of the cold weather preparedness standard. Nor does it make sense for the system operator to have to call the hydro facilities in accordance with TOP 3-5 or IRO 10-3 if extreme cold weather is going to impact the area. Hydro facilities in general are typically enclosed in a structure to protect them from the elements, they have a well understood source for energy that varies seasonally and are not affected by extreme cold weather in the same way thermal facilities are, and they have been operating for over 100 years in all weather conditions. Alternatively, the exclusion of “Hydro Generating Facilities” from the “Facilities” definition would also be acceptable. R6- reads, “… and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall…” Should this section read “… and (ii) the ambient conditions at the site at the time of the event are at or ***below*** above the temperature documented in Part 3.4.2 shall…”?	
Likes 0	
Dislikes 0	

Response

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

Comment

Tacoma Power recommends clarifying the scope of equipment included in the definition of a “generating unit” in the technical rationale for EOP-012-1 R1. For example, the technical rationale should clarify whether the high or low side of the GSU is considered part of the generating unit, whether transmission equipment (e.g. transmission lines above the power station) are included in the assessment, if supporting equipment not directly on-site of the power station is included (e.g. an upstream intake or screen house), and whether equipment housed in a heated building needs to be assessed to extreme cold weather temperatures. Tacoma Power primarily owns hydroelectric generation and most of the important equipment necessary for operations is housed in a heated facility and is not exposed to ambient temperatures.

Tacoma Power supports the comments submitted by LPPC.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	
Document Name	

Comment

1. Has question 8 in this document been purposely omitted?

2. Can the SDT distinguish the difference between the below in EOP-012

- Min. hourly Temperature (R1.1)
- Historical operating temperature (R3.4)
- Cold Weather minimum temperature (R4.2)

3. SEC suggests consistency in language relating to weather temperature in EOP-012. A recommended change would be “minimum recorded temperature” or “sustained lowest temperature”.

4. Asking for previous decades of temperatures is burdensome on the entities as public data available is recorded by month or by years, not hours. Please clarify how entities would obtain hourly temperatures.

5.   For EOP-012 R6, SEC recommends “cold weather” be added before “event resulting in a derate of more than 10%....” The term “event” seems vague.

6.   EOP-012 R4 seem duplicative. Suggested language “Once every five calendar years, each Generator Owner shall review documented temperature data and updated its cold weather preparedness plan”

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	
Document Name	

Comment

Question 8 reaponse is a negative with the following comments:

The Standard is a gross overreach of Federal power. The costs for implementing the Changes to EOP-011-3 and EOP-012-1 will be mitigated through an extended implementation plan and through the suggested adjustments to the requirements of the Standards.

Question 10:

While the proposed standards provide criteria to guide GO/GOP to implement cold-weather operating capabilities, there is no requirement that the generators actually operate properly during cold weather. Without a results-based requirement that the generators actually operate properly in these conditions (e.g. a compliance violation should they not), the standards fall short.

Likes 0	
Dislikes 0	

Response

Israel Perez - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

None.

Likes 0	

Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
See comments provided by Glen Farmer from Avista	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	
Document Name	
Comment	
As proposed, EOP-011 has the unintended consequence of requiring VELCO and other transmission-only entities to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies in Vermont's Transmission Operator Area. VELCO requests that the Standard Drafting Team revise EOP-011 and the Technical Rationale with due consideration to areas of the ERO Enterprise for which the Transmission Operator does not serve as a Distribution Provider nor UFLS-Only Distribution Provider.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
Question 8. was not on the comment form. The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.	

Answer = NO Using a benchmark of the 1975 lowest temperature criteria seems excessive and not likely achievable for the aging generation plants. Also, over time using the 1975 criteria will muddy or dilute weather data. Rather than looking to a specific date in time, we recommend the drafting team determine a set amount of years back GOs will be required to look. This will help account for changes in local climate, while still accounting for infrequent weather events.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	
NRG appreciates the comprehensive work that the SDT has provided in short order to address the first 4 requirements of the FERC report on Texas Storm Uri. NRG also is appreciative of the opportunity to provide comments for consideration to this team. NRG does believe that additional criteria are required to improve reliability and protect the grid from extreme cold weather conditions to prevent another unexpected event like Uri. NRG would like the SDT to address our concerns on the use of minimum hourly operating temperature requirements extreme costs without cost recovery mechanisms to implement R1 and R2, and the undue burden being placed on the fossil fuel generation sector to protect the grid for extreme weather condition in the near-term. Technical exemptions may give an unfair advantage to exempting many renewable technologies while placing an unfair burden on conventional fossil fuel technologies that already run on slim margins. NRG is generally supportive of the balance of the standard under R3, R4, and R5 as this would be -considered best practice. One area for a proposed change is rewriting EOP-012-2 R3.4.1.2 to be restated as: “Fuel supply contract details, and onsite fuel inventory concerns”. This NAGF language captures information GOPs can share from the fuel supplier companies. *****Note that Q8 is not on this comment form. NRG's response to Q8: No-do not agree. NRG agrees with NAGF’s position that the proposed EOP-012 has a high cost potential and cannot be reasonably implemented in a cost-effective manner as stated in our responses above. Without cost recovery for required modifications, this places an undue cost of capital burden on the generators that cannot pass along the additional costs, thus impacting markets in different and unintended ways up to and including forced retirement which may exacerbate reliability rather than enhancing it.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
It appears that question 8 *"The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report in a cost effective manner. Do you agree?"* was omitted from the SBS form. BPA supports the answer and comments submitted by the US Bureau of Reclamation to question 8 below. Answer = No Comment: The proposed modifications are not cost effective because they universally apply a compliance burden to solve a problem that exists only in a limited geographic area and that is limited to certain types of generation facilities. Further, the proposed ability for Generator Owners to limit the scope of their own applicability (i.e., use of "as defined by the Generator Owner") precludes the implementation of meaningful change.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	2021-07_Comment_Form_MRO-NSRF_06-15-2022_Final-V2.docx
Comment	
The practice of designing a system to a temperature that has been experienced for one hour over the past 47 years seems unreasonable. If a minimum design temperature is specified by this project, it seems more reasonable to take a statistical approach, similar to that used by NRC for nuclear generation unit requirements. For the sub-parts of Requirement R1, we request addition of the term "freeze protection" or "freeze protection measures" to the language. As currently proposed, the sub-parts could, if taken individually, be interpreted as requirements for the plant design, rather than the design of the freeze protection measures. The MRO NSRF would ask the drafting team to consider careful usage of the words "unit" versus "plants". Each individual wind turbine or solar inverter is a NERC "unit". This will drive unintended impacts using NERC zero defect standards. NERC should focus on the loss of the aggregate "plant", not the individual "unit".	

The MRO NSRF would request clarification on what “hourly” minimums are defined as or what data an entity should be looking for. Typically, NOAA weather stations take hourly observations, the data of which is stored in a database that is available here (https://www.ncdc.noaa.gov/cdo-web/search). The lowest temperature observed on a given day is listed as a daily minimum temperature. Is the SDT asking entities to drill down to what exact time the temperature was recorded? This would require unneeded extra administrative work and possibly interfacing with local National Weather Service forecast offices to further clarify what time the observation was recorded. A somewhat cursory review of the February 2021 FERC/NERC/Regional Entity report shows no mention of this “hourly temperature” specificity, nor does the SAR for this project.

The MRO NSRF would ask for personnel or persons to be removed from the R5 VSL. The MRO NSRF is concerned that personnel or persons will take the emphasis off proper training for the plant or appropriate “units”.

Regarding the timeline requirements of R6.1, NSRF recommends replacement of the text of the requirement with, “Develop a CAP within 150 days after the event”. If the event were to occur during the month of February, development of the CAP would be required before the end of July. This 30-day (20%) deviation from the language proposed by the SDT seems inconsequential, and would greatly simplify tracking and procedure requirements necessary by registered entities.

In regard to clarification of the scope of Requirement R6, we recommend the following text for R6.:

“Each Generator Owner that owns a generating Facility that experiences an event resulting in a total capacity derate of or could have resulted in a total capacity derate of:

• 10% or greater than or equal to 20MVA, whichever is greater, for generating resources identified under Inclusion I2 of the BES definition, or

• 10% or greater than or equal to 75MVA, whichever is greater, for generating resources identified under Inclusion I4 of the BES definition

for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner’s equipment within the Generator Owner’s control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall:”

The MRO NSRF believes that the proposed language in EOP-012-1 may have the unintended consequence of reducing the available generation during the winter period similar to what occurred with Blackstart Resource(s) due to previous revisions to NERC Standards.

Please note that questions 8 from the unofficial comment form is not available in the SBS, as such the MRO NSRF provides the following response:

8.The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.

Response: NO

Comments:

The lowest temperature since 1975 criteria as stated in R1.1 has the potential to cause entities to incur significant costs and therefore allow entities to either declare exemption through R1.4.4 or decommission generating units. The declaration of exemption based on commercial constraints as stated in R1.4.4 would not increase performance over the current state, and the decommissioning of units would have the unintended consequence of decreasing the resiliency of the grid by removing otherwise sufficient capacity from the market.

A more cost-effective approach would be to remove R1 completely, rely on the CAP criteria of R6 as written to improve existing units reliability in cold weather, and incorporate a statistical approach to low temperature operation for new builds rather than an absolute all-time low.

Likes 2	Corn Belt Power Cooperative, 1, brusseau larry; Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	
Document Name	

Comment

Response to Q8:

No. NRG agrees with NAGF's position that the proposed EOP-012 has a high cost potential and cannot be reasonably implemented in a cost-effective manner as stated in our responses above. Without cost recovery for required modifications, this places an undue cost of capital burden on the generators that cannot pass along the additional costs, thus impacting markets in different and unintended ways up to and including forced retirement which may exacerbate reliability rather than enhance it.

Response to Q10:

NRG appreciates the comprehensive work that the SDT has provided in short order to address the first 4 requirements of the FERC report on Texas Storm Uri. NRG also is appreciative of the opportunity to provide comments for consideration to this team. NRG does believe that additional criteria are required to improve reliability and protect the grid from extreme cold weather conditions to prevent another unexpected event like Uri. NRG would like the SDT to address our concerns on the use of minimum hourly operating temperature requirements extreme costs without cost recovery mechanisms to implement R1 and R2, and the undue burden being placed on the fossil fuel generation sector to protect the grid for extreme weather condition in the near-term. Technical exemptions may give an unfair advantage to exempting many renewable technologies while placing an unfair burden on conventional fossil fuel technologies that already run on slim margins.

NRG is generally supportive of the balance of the standard under R3, R4, and R5 as this would be -considered best practice. One area for a proposed change is rewriting EOP-012-2 R3.4.1.2 to be restated as: "Fuel supply contract details, and onsite fuel inventory concerns". This NAGF language captures information GOPs can legally share from the fuel supplier companies.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

For Question 8's cost effective approaches -

FE feels these obligations can be fulfilled in a cost effective and timely manner as long as the Implementation Plan maintains its proposed 18-month time frame for EOP-011-3.

FirstEnergy disagrees with the proposal to only allow 42 months after the implementation of EOP-012-1 for Requirements R1 and R2. Instead, we ask for the full 60 months after the implementation of EOP-012-1 for R1 & R2 in order to plan and implement these requirements.

FirstEnergy supports EEI's additional comments toward clarifying the language of critical loads.

Also, FirstEnergy suggest review of edits for VSL to ensure clarity.

VSL for R1's Lower should read "…Parts 1.1 – 1.3 for up to 5% **of** its units…" adding the "of" VSL for R2's Moderate, High and Severe read "The Generator Owner did not document its determination and the constraints described in Requirement R1 Part 2.1 for more…" but should read "The Generator Owner did not document its determination and the constraints described in Requirement **R2** Part 2.1 for more…" changing R1 to R2

VSL's for R6 would need to be written as number of events not developed rather than by percent. With 6 items listed under 6.2, to be High is stated as more than 10% but less than 15% which we are reading as more than .6 but less than .9 of the events listed.

VSL for R6 should be written similar to R3's VSL - **The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R6.**

Likes 0	
Dislikes 0	

Response

Tony Skourtas - Los Angeles Department of Water and Power - 3

Answer	
Document Name	

Comment

Question #8 is missing: Comment for question # 8 is as follows: We suggest for the requirement to include cold weather frequency and duration of the criteria to determine if additional cold weather and freeze protection measures need to be implemented. This would allow for generating units in tropical climates that may rarely experience momentary freezing temperatures to more cost effectively implement the standard.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports the EEI comments that ask the SDT to provide clearer language stating that the "critical loads" as identified in EOP-011-3 (see Requirement R1, subpart 1.2.5.2) are solely those critical load necessary for the reliable operation of the BES, and should not be confused with the critical loads (e.g., hospitals, police stations, emergency management facilities, etc.) managed by DP under the authority of state and local public service commission rules and outside NERC regulatory authority. Dominion Energy also seeks clarity on why the title of EOP-011 is being changed to the term preparedness. EOP-011 still contains a preparedness aspect and the planning horizons are still being used in the requirements.	
Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	
We believe the following edits be made to R6: **Derate threshold** We have both substantive and clarity/consistency concerns regarding R6. With respect to the substance, the choice of a derate of 10% of the unit's capacity as the threshold does not seem to be supported by any technical analysis, and would be unreasonable in the case of small generators. If a	

derate threshold is retained, the SDT should consider making it “the greater of” some percent of the unit’s capacity or a MW value, e.g. “10% of the total capacity of the unit or 10 MW, whichever is greater,” and/or tying it to reserve requirements.

Clarifications

“a specified start-up time”

Failure to synchronize “within a specified start-up time” is vague to the point of unenforceability: it could mean the minimum start-up time that the GO has communicated to its BA (assuming that every GO has done so), but there is nothing in the proposed text preventing an auditor from deciding that some other “specified time” should have been used. We suggest that “minimum start-up time” be added to the cold weather preparedness plan in R3 (possibly under R3.4.1), and then referenced in R6, i.e. “a start-up failure where the unit fails to synchronize within the start-up time specified in the applicable cold weather preparedness plan.”

Other necessary clarifications

The text of R6 is unclear in other ways. In particular, (1) the word “event” is used in different places to mean either (i) a derate, failure to start, or Forced Outage, or (ii) the cause of the derate, failure to start, or Forced Outage; (2) it is syntactically ambiguous whether the two numbered preconditions in R6 (“for which (i) the apparent cause(s) of the event…”) must be met with respect to all three types of issue, or only with respect to Forced Outages; and (3) “freezing of equipment” is vague: does it include icing, or only freezing of the liquid components of generation equipment? We propose edits to address the first two concerns, including making R6 an if-then statement with three preconditions; if all three are satisfied, the subrequirements are applicable. This does not change the meaning of the SDT’s proposed text; it simply clarifies it by making all three preconditions explicit.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

DTE Electric supports NAGF comments.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	
Document Name	

Comment	
Response to Question 8 For Canadian entites, the necessary cold weather practices are already in place. The administrative burden associated to the tasks being required in the standards outweigh the reliability benefits, as we already have a good handle on planning, operations and maintenance activites in cold (and even extreme cold) weather. **Question 10** • We support the RSC comments. Additionally, • For Canadian entites, operation of hydroelectric generating units in cold weather condition is part of the normal operating conditions. The design, maintenance and operation of the generating units are done accordingly. For example, the generating units being installed indoor (either in a powerhouse or underground), they do not require specific freezing measure protection. • Sub requirement 1.2.5.3 and 1.2.5.4 of Requirement 1.2.5 in EOP-011-3 state: 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. If, for certain region, there is no provision to minimize the overlap of circuit because the load is insufficient, how does an entity comply with the requirement? • Sub requirement 1.2.5.1 of Requirement 1.2.5 in EOP-011-3 states: 1.2.5.1 Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency; What amount of load should be available for operator-controlled manuel load shedding? • Consider removing the Time Horizon and VRF columns in the EOP-011-3 VSL Table. • Requirement R3 in EOP-012-1 reads that “each GO shall implement and maintain one or more cold weather preparedness plans …” where as R5 refers to “implementing cold weather preparedness plans developed pursuant to R3.”. The SDT should consider revising R3 to include “develop, implement and maintain one or more cold weather preparedness plans”.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	

ISO-NE supports migrating all GO/GOP requirements for Cold Weather in EOP-011 to EOP-012. This retains the focus for EOP-011 and provides the dedicated location for GO/GOP Cold Weather requirements under EOP-012.

ISO-NE also supports the comments from the SRC Group.

Question #8 Is not included in the form.

ISO-NE has no Comment on Question #8

Likes 0	
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment

Reclamation again recommends the standard be limited to generating equipment located outside of temperature-controlled buildings. Reclamation observes that the proposed requirement to identify the coldest hourly temperature experienced at each generating unit since 1975 will result in the expenditure of millions of dollars by entities whose generating units are indoors, only to find that the units successfully operated at historic low temperatures. An exercise to mathematically justify successful operations is not an efficient use of resources and will not improve reliability.

This is the answer to question #8 from the unofficial comment form that does not show up on this Comment Form. The proposed modifications are not cost effective because they universally apply a compliance burden to solve a problem that exists only in a limited geographic area and that is limited to certain types of generation facilities. Further, the proposed ability for Generator Owners to limit the scope of their own applicability (i.e., use of “as defined by the Generator Owner”) precludes the implementation of meaningful change.

Likes 0	

Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation would like to ensure that the SDT makes it very clear in what they are trying to mean by "Operating a plant during cold weather". We feel they are trying to mean "generation facilities applicable as defined in EOP-012, R.2. Facilities" - to produce power during the defined cold/extreme weather period, whether the plant is on-line or off-line, despite the conditions. The way the verbiage is in various parts of EOP-012, it is unclear and could very easily be interpreted to mean "Maintain on-line operation". Is the SDT & NERC intending for entities to be able to restore our generators at any time? We would like to see more clarity on what is meant by 'operating during cold weather'.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3	
Answer	
Document Name	
Comment	
WEC Energy Group supports EEIs comments, noting that Question 8 was omitted from the survey.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
FOR Q10:	

PG&E supports the comments provided by the North American Generators Forum (NAGF) comment related to "equipment freezing"..

FOR Q8 THAT IS MISSING FROM THE SBS INPUT:

Answer is - NO

Comment is -

PGAE supports the North American Generators Forum (NAGF) comments. PG&E also has the following comments:

The Standard as written does not provide a method or means to recoup costs associated with plant design upgrades. The performance of expensive analysis, training and design changes that are not commensurate with grid reliability and risk reduction do not appear to be cost effective.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

In proposed EOP-12-1 Requirement Part 1.1 Texas RE inquires which criteria is used to determine what “reliable data” is or is not. Texas RE recommends this criteria be captured in the GOs’ cold weather preparedness plans.

Texas RE noticed that the definition of Energy Emergency includes LSE, which no longer a registered function.

Texas RE recommends modifying the verbiage in Requirement Parts 1.4.4 and 6.2.6 from “a declaration” to “Documentation, where deemed appropriate by the Generator Owner based on the review of Parts 1.4.1 through 1.4.3, that no revisions to the cold weather preparedness plan(s) are required…”. Texas RE recommends this information be submitted to the BA so the BA is aware of the generating units within its footprint. This supports key recommendation 1g – providing great specificity on the roles of the GO, GOP, and BA in determining generating unit capacity that can be relied upon during forecasted cold weather.

Texas RE is concerned there is no ending timeframe for CAPs in Requirements R1.4 and R6. Additionally, Texas RE recommends CAPs be filed with the BA so the BA understands operating limitations.

Requirement Part 3.4.2 requires three options for temperature to be included in the GO's cold weather preparedness plan. Requirement Part 1.4, however, specifies "each generating unit shall be designed and maintained shall be designed and maintained to be capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975". If the units are required to be designed according to Requirement Part 1.4, what is the purpose of the three options in Requirement Part 3.4.2?

Additionally, Requirement R6 references Requirement Part 3.4.2, which is merely included as part of the cold weather preparedness plan and not necessarily what the generating unit would be designed for in accordance with Requirement Part 1.4.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4, Group Name NCPA

Answer	
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Additionally, NCPA agrees with the comments provided by Avista Corporation and the MRO NSRF.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators

to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA

Answer	
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report [The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov)] the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPCO signed on to ACES comments below:

In regards to determining the minimum hourly temperature to which generating units should be designed and maintained to be capable of continuous operations: was there any consideration of utilizing future forecasted minimum temperature data rather than, or in addition to, historical temperature data?

Question number 8 was missing, therfore it has been added here with the comments:

The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.

Answer:

No

Comments:

The SAR does not prescribe the historical minimum hourly temperature threshold as prescribed in EOP-012-1. Rather than imposing additional financial obligations for GOs to implement freeze protection for the worst historical conditions, allow GOs to implement a risk-based freeze protection approach. Allow GOs to protect their systems to a known ambient condition, and communicate this capability to the BA for the development of a winter season dispatch plan.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards. To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 5

Answer	
Document Name	

Comment

Changes to Cold Weather Reliability Standards should not be applicable continent-wide. Standards should not be modified or implemented prior to Market Rule Modifications. See prior NERC Project 2019-06 ballot and commenting by Marty Hostler

Market Rule modifications have not yet been made to mitigate potential Cold Weather Events grid issues. Per FERC/NERC's recommendation, Market Rule modifications should be made prior to, or concurrent with, development of new Standards.   To date, no known Market Rule Modification project has been initiated.

On page 86 of FERC/NERC's joint Report The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (ferc.gov) the following recommendations where made.

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach should be used to address the following needs: • The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:

While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

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

Missing Question #8: The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.

- **YES**, Southern Company can agree that the modifications in EOP-012 are cost effective so long as the GO continues to define "cost effective" by declaring what constitutes a technical, commercial, or operational constraint to meeting the stringent criteria for minimum low operating capability as defined in EOP-012-1 Requirement R1.1.

QUESTION #10: Provide any additional comments for the standard drafting team to consider, including the provided technical rationale document, if desired.

- Southern Company supports the EEI comments.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	

Comment

Answer to question 8: No.

Comments: See comment above for question 4 related to temperature monitoring requirements at the plant site. We do not currently monitor the temperature at each facility, adding this requirement for each plant, including the associated calibrations and certifications to ensure the equipment is operating properly to monitor temperature is not cost effective. We believe that monitoring the temperature on public, regional, national weather service sites for a region within 150 miles of the temperature equipment will be much more cost effective and will satisfy the intent of the standard. Whether the temperature at one site is -20 degrees or another is at -22 degrees, we will still be operating during extreme cold weather for the entire region equipment can freeze and likely has been susceptible for freezing all winter prior to the event. Additionally, related notifications for extreme cold weather events should be allowed to be broadcast to a GO or GOP region rather than on a plant-by-plant basis.

Additional General Comments:

Introduction, Section 4.2 - Please modify the definition of "Facilities" to include only "Thermal Generating Facilities - facilities that use a fuel source such as hydrocarbons, human or other derived trash, and/or facilities that use the heating and/or cooling of water to generate electricity". Thermal generating facilities as defined above appear to be the primary intended target of this standard and are the most susceptible facilities for extreme cold weather. The standard specifically calls out things for us to assess for each facility such as "Fuel Switching Capability," "Fuel Supply and Inventory Concerns" and "Environmental Concerns" (i.e., Environmental Permitting Concerns). Preliminary review of this standard in accordance with EOP-11-2 for our Hydro Generating facilities has not identified any significant impact to the operation of our facilities, maintenance practices, or limitations on operation due to temperature. An ongoing review of our hydro facilities every five years for fuel switching capabilities, fuel supply and inventory concerns, and environmental permitting concerns, design temperature concerns, etc. for our hydro facilities will be an ongoing paperwork exercise and does not seem to align with the intent of the cold weather preparedness standard. Nor does it make sense for the system operator to have to call the hydro facilities in accordance with TOP 3-5 or IRO 10-3 if extreme cold weather is going to impact the area. Hydro facilities in general are typically enclosed in a structure to protect them from the elements, they have a well understood source for energy that varies seasonally and are not affected by extreme cold weather in the same way thermal facilities are, and they have been operating for over 100 years in all weather conditions. Alternatively, the exclusion of "Hydro Generating Facilities" from the "Facilities" definition would also be acceptable.

R6- reads, "… and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall…" Should this section read "… and (ii) the ambient conditions at the site at the time of the event are at or ***below*** above the temperature documented in Part 3.4.2 shall…"?

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

Response to Question #8:
Answer: "No"
Comments:
Section R1.1 states that each generating unit "shall be *designed* and maintained capable of continuous operations", however changing the design of existing facilities is a challenging (and at times, infeasible) endeavor and may not be the most cost effective way to accomplish cold weather hardening for existing units. Many facilities are successfully and economically using temporary enclosures, heaters, insulation blankets etc. which are installed during the winter season and later removed. The word "designed" in the standard does not seem to recognize this current and successful practice as a prudent way to ensure a unit is capable of continuous operation during severe cold winter weather.

Response to Question #10:
Comments:
The proposed revisions for EOP-011 include the term "critical load," which for purposes of the standard would infer loads critical to the operation of the BES. However, many local jurisdictions also use the term "critical load" to describe loads that are *not* related to the BES. AEP recommends that the SDT look for ways to clearly differentiate that term to avoid confusion.

In addition, AEP supports the comments made by EEI on EOP-012-1 regarding difference in generating units as reflected in the BES definition.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	
Comment	
Ameren agrees with the NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Mark Young - Tenaska, Inc. - 5	
Answer	
Document Name	EOP-012 Comments - Tenaska Final.docx
Comment	
See attached Wod document. Also, in regards to question #8 that was removed the original version of this form, we do not agree that the newly drafted EOP-012-1 meets the key recommendations in The Report in a cost effective manner.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	NAGF EOP-012-1 06152022 final.pdf
Comment	

NAGF Comments: The NAGF recognizes that the events of February 2021 were catastrophic. However, the timeline that is being used to rush these proposed standards through the process is causing the SDT to rush the effort with no time to coordinate these efforts with the requirements within this standard, let alone other standards. As an example, Requirement 1 requires units to be designed to meet certain capabilities regarding wind, moisture and temperature, yet R3 asks only about temperature and ignores the wind and precipitation impacts required in R1. Requirement R6 uses the term “equipment freezing” yet does not define what this means. Should industry assume that freezing means water turns to ice, causing a disruption in the generation process? If so, does that mean blade icing is freezing? The report supporting the modifications to the standards uses the term freezing but includes issues unrelated to water turning to ice. The drafting team needs to clarify exactly what events the Generator Owner is expected to protect against as we go forward.

Unfortunately, the rush to complete the standard is pushing industry to approve a disjointed standard that is unlikely to provide much, if any, improvement in generator performance while ignoring the fact that the Balancing Authorities and Transmission Planning functions are not currently asking for or utilizing the information needed to improve system planning. The NAGF believes that rather than rushing to complete a poorly structured standard, NERC would be better served to create a good standard in a reasonable amount of time. The NAGF feels that the proposed standard fails to provide significant value in large part due to the rush to the finish line. As currently structured, it is more likely to cause the creation of numerous of documents that will state that there is a technical, commercial or operational constraint and therefore the generator will make no changes instead of a significant improvement in generator's ability to operate in extreme cold conditions, until such time as it is clear where the compensation for the investment will come from.

The NAGF has provided a revised EOP-12-1 standard for consideration that address the issues identified throughout these comments in a reasonable manner. Please review the proposed requirements and other suggested changes to the standard. The proposed revisions would require verified weather capability information be provided to the BA, RC, TOP and TP while providing the same clarity of what is desired for existing generation and requiring the proposed (or better) weather capability for new generation going forward. Existing generation can determine whether the investment in modifications is worth the potential payback based on the generator's specifics. This provides the same value with much greater clarity as the SDT's proposed requirements.

Thank you for the opportunity to comment. The NAGF looks forward to continuing to work with NERC and FERC to help draft a reasonable standard that addresses improved reliability while waiting for the other recommendations from the report to be addressed.

Question #8: The NAGF does not support that the modifications in EOP-011-3 and the newly drafted EOP-012-1 meet the key recommendations in The Report in a cost-effective manner.

NAGF Comments for Question #8:

As drafted, the requirements in the proposed EOP-012 have an unlimited cost potential and cannot reasonably be implemented in a cost effective manner. Please see the responses provided above for the NAGF's reasoning. The NAGF recommends that the drafting team first address having the Balancing Authorities and Transmission Planners use the information related to expected weather startup and operational capability to determine where units need to improve before creating a blanket requirement for all generators to perform unlimited retrofits without a clear means of compensation. As noted above, without compensation for the required modifications, NERC is putting the Generator Owners at greater financial risk, which will cause increased cost of capital and a needed higher return on equity while driving market prices down. The NAGF has provided a revised EOP-012-1 standard for consideration that address these issues in a reasonable manner. Please review the proposed changes to the standard.

Likes 0	
Dislikes 0	
Response	

Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	

Response to Q8: No - See Q8 Comments below

For EOP-012-1, Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft.

However, as noted in Invenergy's response to Question 4, the current proposal yields an arbitrarily stringent standard that could impose more onerous requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days -

that this Standard is intended to address. The alternative approach Invenergy suggests would reasonably be expected to yield a more cost-effective approach to meeting the key recommendations in the Joint Inquiry Report.

Lastly, Invenergy agrees with “Key Recommendation 2” from the Joint Inquiry Report, which directly considers cost:

Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions (or designing any new units they may build) through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end users’ service rates. The applicable ISOs/RTOs (market operators) and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments. (Winter 2022-2023)

Comments for Q10

Invenergy recommends replacing the 10% derate performance trigger in R6 with a loss of 75 MVA. This ties the requirement more closely to existing presumptions of what level of loss impacts BES reliability, and provides more balance in the application of the Requirement across generation types and facility size.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

In response to Question 8, Invenergy votes "No" with the following comments:

For EOP-012-1, Invenergy is unable to quantify the overall costs and benefits to arrive at a definitive conclusion about the cost effectiveness of the current draft.

However, as noted in Invenergy’s response to Question 4, the current proposal yields an arbitrarily stringent standard that could impose more onerous requirements than are necessary to ensure generator availability during the prolonged extreme cold events – occurring over multiple hours or days - that this Standard is intended to address. The alternative approach Invenergy suggests would reasonably be expected to yield a more cost-effective approach to meeting the key recommendations in the Joint Inquiry Report.

Lastly, Invenergy agrees with “Key Recommendation 2” from the Joint Inquiry Report, which directly considers cost:

Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions (or designing any new units they may build) through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end users’ service rates. The applicable ISOs/RTOs (market operators)

and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments. (Winter 2022-2023)

In response to Question 10, Invenergy has the following comments:

Invenergy recommends replacing the 10% derate performance trigger in R6 with a loss of 75 MVA. This ties the requirement more closely to existing presumptions of what level of loss impacts BES reliability, and provides more balance in the application of the Requirement across generation types and facility size.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5

Answer	
Document Name	

Comment

(**NOTE:** For Question 8, which did not appear in this form, AE comment is "No Opinion".)

Question 10 Response:

AE recommends clarifying the scope of equipment included in the definition of a “generating unit” in the technical rationale for EOP-012-1 R1. For example, the technical rationale should clarify whether the high or low side of the GSU is considered part of the generating unit, whether the transmission equipment (e.g. transmission lines above the power station) are included in the assessment, if supporting equipment not directly on-site of the power station is included (e.g. an upstream intake or screen house), and whether equipment housed in a heated building needs to be assessed to extreme cold weather temperatures.

AE is endorsing an Affirmative vote for EOP-011-3 and a Negative vote for EOP-012-2. The Negative vote for EOP-012-2 is to provide constructive criticism for the creation of a new revision that will:

- Include the BA to be included as a responsible functional entity and to include the “winter season” determination as a Requirement
- Modify the hourly temperature collection and analysis to more reasonable solution
- Refine the scope of “generating unit”
- Clearly limit data collection to a Section 1600 Data Request, based upon precedent

Likes 0	
Dislikes 0	

Response

Tom Vinson - American Clean Power Association - 5

Answer	
Document Name	ACP redlines for NERC project 2021-07.docx

Comment

ACP recommends the following revisions to the following sections not specifically teed up in this series of question. Attached are specific redline recommendations.

1. ACP recommends clarifying the “facilities” definition in 4.2 to make it clear that compliance under the proposed standard is facility-wide for dispersed power resources, not unit-by-unit. This is important for wind farms and solar facilities that are made up of several distinct generating units aggregated to the facility level. In other words, for example, a corrective action plan, if needed, should apply at the facility level, not the individual wind turbine level or a subset of solar panels in a facility.

2. In R6, ACP is concerned about the 10% trigger and recommends an alternative methodology tied to the BES definition. As currently drafted, the 10% trigger could impose a significant administrative burden on GOs of dispersed generation resources. In the event of such a derate, staff would have to assess the temperature at which it happened, whether the apparent cause was due to freezing, and whether that cause was within the generator’s control. For dispersed generating resources, this would potentially have to be done on a unit-by-unit basis. One ACP member has calculated using historical data that for one facility, it would average 2.7 analyses per day with 3 hours per analysis.

In addition, while perhaps such as administrative burden would be justified if reliability impacts were possible from the derate, ACP is concerned the 10% trigger is arbitrary and unrelated to any consideration of BES reliability impacts.

ACP notes NERC Project 2014-01 Standards Applicability for Dispersed Generation Resources for NERC Reliability Standard PRC-004 Protection System Misoperation Identification and Correction takes a different approach. The SDT white paper for that project finds:

- “However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting, and developing Corrective Action Plans for each individual generating unit that trips at a dispersed power producing resource site, as the tripping of one or a small number of these units has no material impact to BPS reliability.” (p. 23)
- “Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations.” (p. 24)

Therefore, ACP recommends the attached redline to tie the trigger to a presumption of impacts to BES reliability.

Should the SDT nonetheless maintain the 10% trigger, ACP recommends attached redlines to clarify how it applies in the case of dispersed generating resources.

First, it is unclear if the 10% trigger applies facility-wide or on an individual unit basis (i.e. wind turbine or PV panel section)? ACP believes it should apply on a facility-wide basis.

Second, it is unclear if it is it based on nameplate capacity or available capacity? ACP believes the lower threshold 10% trigger should be based on available capacity since wind and solar generation are weather dependent and not always generating at nameplate capacity.

ACP proposes the attached redline for consideration.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Aaron Casto, Florida Municipal Power Pool, 6; Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; David Owens, Gainesville Regional Utilities, 1, 5, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; Neville Bowen, Ocala Utility Services, 3; - LaKenya VanNorman, Group Name FMPA and Members

Answer	

Document Name	
Comment	

Question 8: The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.

Possible Answer: No

Comments: For the reasons discussed above associated with R1 of EOP-012-1, we do not believe this will be cost effective. In fact the cost impacts will be arbitrary -in some areas this will cost substantially more than it should, while in other areas it may cost less (e.g. by requiring less cold weather protection than may actually be warranted). The current language of R1 implicates absolutely massive construction projects for every plant in Florida, which will drive entities to indicate it is not economically feasible (which we wonder, given the current language of the standard, whether that will be allowed or not – seems to be up to the auditors which is not how we want standards to be applied). Whereas if a probabilistic approach is applied, we believe this will allow a more refined determination of what level of cold weather protection is required at each given plant.

In addition to the issues with R1 and R2 of EOP-012, FMPA has the following concerns.

R4 – If an event occurs that is outside the temperature range identified for the plant site, that should trigger a Plan update. Otherwise it would take up to 5 years to recognize the new potential range of temperatures. This has effects on several requirements.

R5 – Requirement is really two requirements that should be parsed and clarified – training of staff on cold weather preparedness plan, and GO/GOP jointly determining who should conduct the training.

R6 - “Apparent cause of the event is freezing” – should say “effects of cold weather, including but not limited to freezing”. This allows for cold weather affects that may not necessarily be freezing to be considered.

R6.1 – A CAP is just a project. The other items in 6.2.1 through 6.2.6 belong in a Root Cause Analysis, the result of which would determine a CAP. We believe a preliminary RCA should be required ot be completed in advance of the July 1st date which would also include an operations plan for the subsequent winter if the CAP cannot be completed in time.

Likes 0	
Dislikes 0	
Response	
Summer Esquerre - NextEra Energy - 5	
Answer	
Document Name	
Comment	

NextEra Energy (NEE) supports the weather emergency preparedness objectives and the development of standards and respectfully submits that any weatherization standards adopted through this rulemaking should strike a careful balance of fulfilling the mandates required without discouraging future investment or financially burdening existing generation. NEE recommends that cold-weather weatherization requirements consider Original Equipment Manufacturer (“OEM”) limits and available technologies, and not require weatherization beyond what is commercially available, especially for renewable generating resources. Although other weatherization technologies are still being researched, they are not commercially available today. It is important that generators maintain their generation equipment consistent with the OEM design. Requiring operations or retrofits outside of the manufacturer's parameters or adopting unproven technology can reduce overall reliability. NEE also notes that increased cold-weather weatherization of renewable generating resources, such as wind turbines, carries the unintended consequence of decreasing the OEM high temperature operational limit.

NEE also supports the comments submitted by the Electric Edison Institute.

Likes 0	
Dislikes 0	

Response

Lisa Martin - Austin Energy - 6

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

LPPC recommends clarifying the scope of equipment included in the definition of a "generating unit" in the technical rationale for EOP-012-1 R1. For example, the technical rationale should clarify whether the high or low side of the GSU is considered part of the generating unit, whether the transmission equipment (e.g. transmission lines above the power station) are included in the assessment, if supporting equipment not directly on-site of the power station is included (e.g. an upstream intake or screen house), and whether equipment housed in a heated building needs to be assessed to extreme cold weather temperatures. For those that primarily own hydroelectric generation, most of the equipment necessary for operations is housed in a heated facility and is not exposed to ambient temperatures.

LPPC has endorsed an Affirmative vote for EOP-011-3 and a Negative vote for EOP-012-1. The Negative vote for EOP-012-1 is to provide constructive criticism for the creation of a new revision that will:

1. Include the BA to be included as a responsible Functional entity and to include the "winter season" determination as a Requirement;

2. Modify the hourly temperature collection and analysis to a more reasonable solution;

3. Refine the scope of “generating unit”;

4. Clearly limit data collection to a Section 1600 Data Request, based upon precedent.

Response to Question 8 - YES

These comments have been endorsed by LPPC.

Likes 2	Colorado Springs Utilities, 1, Braunstein Mike; Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merre
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	
Document Name	

Comment

Question 8 Response

As drafted, the requirements in the proposed EOP-012 have an unlimited cost potential and create only an administrative burden on those generators that have a history of reliable operation in extreme cold weather. CEG recommends that the drafting team should first address having the Balancing Authorities and Transmission Planners use the information related to expected weather startup and operational capability to determine where units need to improve before creating a blanket requirement for all generators to perform unlimited retrofits without a clear means of compensation. These concerns could be addressed in Requirement R1.4.4, or in the M1 measures, e.g., "... documentation that no upgrade is required based on information provided by attestation from the BA or TP, or by demonstrated historical operating experience."

Question 10 Response

• CEG considers the Standard as-written too prescriptive and appears to add no value to Generators with a history of successful severe cold weather operation. Suggest the SDT remove prescriptive details of “how” something is to be accomplished and focus instead on the intent to improve cold weather operation. For example, the Standard could simply require that GOPs prepare for cold weather operation without specifying a limiting temperature, demonstrate successful operation, i.e., through measures such as power history or capability curves, and if operation was not successful, development of corrective measures, or justification why none are practical. It would then be up to planning and balancing authorities, market regulators, and market forces, to determine the best mix of additional generation or compensation of existing generation, as part of an integrated BES, to guaranty supply and delivery during cold weather.
• Section 4.2 Applicability. CEG does not think the BA should determine a winter season. CEG would like to suggest the following language as an option. “For purposes of this standard, the term “generating unit” means those Bulk Electric System generators that plan to operate year around. Generators that do not operate during the winter by design are exempt.”

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 5

Answer	
Document Name	

Comment

Question 8 Response: With the EEI proposed changes to R1 and R2, AZPS agrees that EOP-012-1 meets the key recommendations in The Report in a cost-effective manner.

Likes 0	
Dislikes 0	

Response

Rick Stadtlander - NEI - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

None additional

Likes 0	
Dislikes 0	

Response

Kimberly Bentley - Kimberly Bentley On Behalf of: sean erickson, Western Area Power Administration, 1, 6; - Kimberly Bentley

Answer	
Document Name	

Comment

Within EOP-012-1, recommend clarifying how hourly minimums are defined and determined. Would also recommend limit the standard to equipment located outside of temperature-controlled buildings to avoid needless work and avoid excessive use of resources.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Question 8: No response

Question 10 Comments:

Additional Comments for EOP-011-3

EEI recommends clarifying the language stating that the "critical loads" as identified in EOP-011-3 (see Requirement R1, subpart 1.2.5.2) are solely those critical load necessary for the reliable operation of the BES, and should not be confused with the critical loads (e.g., hospitals, police stations, emergency management facilities, etc.) managed by a DP under the authority of state and local public service commission rules and outside NERC regulatory authority. We also ask that DP be added to the applicability section of this Standard, given the critical role that DP plan in the implementation and reporting of load shedding programs.

Additional Comments for EOP-012-1

The difference between "generating units" under the BES definition as defined under I2 and aggregated inverter based resources as defined under I4 should be clarified within EOP-012-1 R6. There are technical and scalability issues to monitoring each individual I4 resource which is technically a BES "unit" for a 4-hour weather related 10% derate.

- **Technical Measurement Issues:** At any given time, a 75 MVA or greater aggregate wind or solar unit may have 10% of individual I4 BES generating resources at the aggregate "plant" out-of-service during a rolling 4-hour period for various reasons including mechanical issues, weather issues, or fuel (lack of wind or sun) issues. This will require programming and human oversight issues to separate and identify a "plant" level rolling 4-hour weather related 10% derate without material reliability benefit.
- **Scalability Issues:** Monitoring any large wind / solar farm or farms with 100 – 300 individual I4 BES Inverter-based resources presents a scalability issue. Monitoring and identifying mechanical issues, weather issues, or fuel (lack of wind or sun) issues will require significant programming and human oversight to separate and identify a "plant" level rolling 4-hour weather related 10% derate without material reliability benefit.

To address this concern, the SDT should clarify for purposes of EOP-012, that Requirement R6 applicability should conform to the following requirements:

For EOP-012, Requirement R6 a BES "generating unit" shall be addressed as follows:

- An individual 20 MVA single shaft unit of 20 MVA or larger as defined in I2 of the NERC BES definition.
- For dispersed power producing resources, as defined in I4 of the BES definition and aggregate to 75 MVA or more at a single Point Of Interconnection (POI) connected at 100 kV or greater; the total plant shall be considered as a single "generating unit" under R6

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5	
Answer	
Document Name	

Comment

Question 8 Response

As drafted, the requirements in the proposed EOP-012 have an unlimited cost potential and create only an administrative burden on those generators that have a history of reliable operation in extreme cold weather. CEG recommends that the drafting team should first address having the Balancing Authorities and Transmission Planners use the information related to expected weather startup and operational capability to determine where units need to improve before creating a blanket requirement for all generators to perform unlimited retrofits without a clear means of compensation. These concerns could be addressed in Requirement R1.4.4, or in the M1 measures, e.g., "... documentation that no upgrade is required based on information provided by attestation from the BA or TP, or by demonstrated historical operating experience."

Question 10 Response

• CEG considers the Standard as-written too prescriptive and appears to add no value to Generators with a history of successful severe cold weather operation. Suggest the SDT remove prescriptive details of "how" something is to be accomplished and focus instead on the intent to improve cold weather operation. For example, the Standard could simply require that GOPs prepare for cold weather operation without specifying a limiting temperature, demonstrate successful operation, i.e., through measures such as power history or capability curves, and if operation was not successful, development of corrective measures, or justification why none are practical. It would then be up to planning and balancing authorities, market regulators, and market forces, to determine the best mix of additional generation or compensation of existing generation, as part of an integrated BES, to guaranty supply and delivery during cold weather.
• Section 4.2 Applicability. CEG does not think the BA should determine a winter season. CEG would like to suggest the following language as an option. "For purposes of this standard, the term "generating unit" means those Bulk Electric System generators that plan to operate year around. Generators that do not operate during the winter by design are exempt."

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Mike Braunstein - Colorado Springs Utilities - 1	
Answer	
Document Name	

Comment

Colorado Springs Utilities agrees with comments endorsed by LPPC

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

None of the NO answers above indicate a disagreement or opposition to the proposed standards. They are meant to offer additional suggestions, as requested by the drafting team. In addition to the comment above, WECC offers the following:

EOP-012 R1: This requirement specifically states a generating unit must be capable of “continuous” operations. Some facilities may be capable of operation in severe cold weather if they are already in operation but a start up in cold weather may be more challenging. The drafting team may wish to consider the language in R1 and clarify if cold weather performance is intended to be satisfied only by units that are in service and running or if the freeze protection measures must be adequate for startup during the specified temperatures. The intent to address startup capability is implied in R6 but may be clarified here and not depend on a linkage between the two requirements.

R1 also states that generating “shall be designed….” Most applicable generating units are already designed and in operation. Does this imply or require a re-design? This requirement could be worded in a more results-oriented way and address these issues. (We do understand the word “design” was used in the FERC recommendations but believe the objective could be met without that word)

Many facilities built since 1975 had no climate data at their specific location. How far away would reliable data have to be to satisfy the criteria “at its location.” Our Recommendation is to consider specifying use of the nearest NOAA weather source.

WECC suggests the Drafting Team consider replacing the words “designed and maintained” in R1, Parts 1.1, 1.2, and 1.3, to “capable?” Also, as per the comment above, suggest the drafting team consider a reference to the nearest NOAA weather source.

As per earlier comments, suggest replacement of “commercial, or operations constraints” to “regulatory constraints” in R1, part 1.4.2. and part 1.4.4

EOP-012 R3: Same comment as above. Consider use of the nearest NOAA weather source in part 3.1.

Since R1 already specifies the freeze protection requirements, WECC suggests the Drafting Team consider removing “based on geographical locations and plant configuration” from part 3.2.

EOP-012 R5: With respect to one function performing “in conjunction with” another function, the use of this phrase is not clear with respect to applicability. If it is viewed by the ERO as being only applicable to the first function (Ref: RSAW's for TPL-001 and TPL-007) this phrase creates ambiguity.

Because EOP-012 was expanded beyond what was in EOP-011, R5 should reference what training is being required. Below is recommended wording for consideration:

“Each Generator Owner shall identify either itself or the Generator Operator as the responsible entity for developing and providing generating unit-specific training on its cold weather preparedness plans developed pursuant to R3 to all maintenance and operations personnel responsible for implementing those plans. And the identified responsible entity shall provide the annual training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R3.”

EOP-012 R6, Part 6.2.6: This recommendation would only be appropriate if the recommended language change for R2 and R4.4 were accepted. Suggest replacement of “commercial, or operations constraints” to “regulatory constraints” and removing the words “as defined by the GO.”

WECC has no comment for Question #8.

Thank you for the opportunity to provide suggested clarifying or improved language.

Likes 0	
Dislikes 0	

Response

Dan Roethemeyer - Vistra Energy - 5

Answer	
Document Name	

Comment

Response to Q8 - No:

Luminant agrees that the proposed standards should meet the key recommendations in The Report in a cost effective manner, but it disagrees that the proposed standards do so as currently drafted. Luminant joins the comments of the Texas Competitive Power Advocates (TCPA), which discuss in detail the specific issues relating to cost effectiveness in the ERCOT region. Competitive generators in ERCOT currently do not have any mechanism for cost recovery for weather preparedness or freeze protection measures and are already facing significant costs from implementing phase 1 weather preparedness requirements of the Public Utility Commission of Texas (PUCT) and will face additional compliance costs to implement the soon-to-be adopted phase 2 PUCT weather preparedness requirements. While the PUCT is considering market design reforms, it is uncertain at this time exactly what those reforms will entail, and there has been no suggestion to date that the PUCT will adopt cost recovery mechanisms for weather preparedness compliance. NERC thus should adopt a standard that will not be as likely to impose significant, unrecoverable retrofitting costs on Generator Owners while still providing an objective and meaningful weatherization standard, such as the alternative standards proposed above under Question 4 (e.g., the 95th percentile minimum average temperature over 72 hours). In addition, NERC should focus the standard on weather preparedness, which is something within the control of the Generator Owner, as opposed to requiring definitive continuous operation at a specific temperature, which would more likely require retrofitting of generation resources to meet those weather performance requirements. If NERC were to modify the standard to require preparing resources such that they are "reasonably expected" to operate continuously at a minimum average temperature over a prolonged period (e.g., 95th percentile minimum average temperature over 72 hours),then a meaningful and objective standard would be set, but one that is less likely to require that Generator Owners expend extraordinary sums to retrofit units to meet the standard and in turn less likely to push economically marginal but reliability-critical resources out of service.

Imposing the current proposedweatherization requirement in EOP-012-1 on resources outside of ERCOT similarly would also be unreasonably burdensome, costly, and unnecessary. While resources outside of ERCOT may have the opportunity for some cost recovery (e.g., operated by rate-regulated utilities), that is not the case for all generators, and it is unclear at this time exactly how those costs would be recovered. For example, if weatherization related upgrades cause a unit to not clear a capacity auction, there is no mechanism for that Generator Owner to recover those costs, especially if they are not rate-based companies. Further, in regions outside of ERCOT, reserve margins are already generally higher, and the grid is interconnected across ISOs that have significant geographic diversity. The alternative standard proposed above (e.g., based on the 95th percentile average minimum temperature over a 72-hour period) thus also makes sense for resources operating in other ISOs.

For both ERCOT and non-ERCOT ISOs, the ability to seek an exception under R2 -- modified, as proposed under Question 5, to include existing resources -- for technical, commercial, and operational reasons is an important feature to ensure that the proposed standards are cost effective in their implementation.

Response for Q10:

Luminant incorporates the additional comments of the Texas Competitive Power Advocates. In addition, the proposed requirement to develop a Corrective Action Plan (CAP) by the earlier of July 1 or 150 days subsequent to the event seems unnecessarily constrained for an event that happens toward the end of the winter season (e.g., February 28), and thus for which a CAP would be due in a much shorter period than 150 days (nearly a month sooner) if the standard requires the earlier of July 1 or 150 days. There is no apparent reason to require a CAP to be developed more quickly for events that occur in February than in other winter months. Even with a 150-day standard across the board, CAPs would be in place well in advance of the next winter season. Luminant thus recommends that the standard simply require a CAP to be developed no later than 150 days subsequent to the event.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	
Document Name	

Comment

Q8. Entergy's response is Yes regarding cost effective. No Comments.

R6.1

The Technical Rationale and Justification for EOP-012-1 states that the intent of R6. is to allow entities to review multiple events holistically following a winter season, and create one CAP for equipment with common failure causes. Entergy's position is that the July 1 deadline supports that intent and 150 days is not necessary.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

Acciona Energy believes that section 4.2 is unnecessary. The intention of the standard is to ensure applicable 'generation Facilities' or 'generation resources' can operate during the winter season. Using either of the two aforementioned terms, ties the applicable equipment back to the NERC Glossary of Terms or the BES definition. Introducing the term "generating unit" causes confusion. Acciona suggests using the term 'generation Facility' because it includes all equipment, BES and non-BES. The standard should only be applicable to the GO and GOP without any further dissection in section 4.

Please note that questions 8 from the unofficial comment form is not available in the SBS, as such the Acciona Energy provides the following response:

8.The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.

Response: NO

Comments:

When considering a threshold to analyze and determine whether or not a derate is caused by cold weather and therefore requires a Corrective Action Plan, the SDT needs to consider the administrative resources required for Generator Owners to complete the analysis. Consider for example a dispersed power producing resources identified under Inclusion I4 of the BES Definition with an installed capacity of 95.325 MW and each individual generating unit is 3.075 MW (31 total individual generating units). The 10% threshold as currently proposed, would equate to four individual generating units offline for four-hours. To determine whether these individual generating units were offline due to the effects of cold weather, administrative personnel would have to analyze the alarm codes and ambient conditions associated with each unavailable individual generating unit. In our analysis of historical data, a winter period for one Generator Owner would average 2.7 analysis per day with 3 hours per analysis.

Acciona Energy would suggest tying the 10% magnitude back to a reliability concept such as the BES Definition: 75MVA/20MVA. The simple reasoning is that for a 100MVA facility, a 10% derate (10MVA) would not constitute a reliability concern as it does not even meet the thresholds to be BES.

Further, Acciona Energy would suggest using the reasoning as develop by Project 2014-01 Standards Applicability for Dispersed Generation Resources for NERC Reliability Standard PRC-004 Protection System Misoperation Identification and Correction. This reasoning is outlined in this team's white paper (https://www.nerc.com/pa/Stand/Pages/Project-2014-01-Standards-Applicability-for-Dispersed-Generation-Resources.aspx). As stated by the 2014-01 SDT:

- However, based on the experience of the SDT, there is minimal impact to BPS reliability for analyzing, reporting, and developing Corrective Action Plans for each individual generating unit that trips at a dispersed power producing resource site, as the tripping of one or a small number of these units has no material impact to BPS reliability.

- Additionally, reporting of Misoperations on each individual generating unit may result in substantial and unnecessary burdens on both the dispersed generation resource owner and the Regional Entities that review and track the resulting reports and Corrective Action Plan implementations.

- The SDT was also concerned with the applicability of events where one or more individual units tripped and the root cause of the operations was identified as a setting error. In this case, the requirements of PRC-004 would be applicable for any individual units where identical settings were applied on the Protection Systems of like individual generation resources identified under Inclusion I4 of the BES definition.

NERC PRC-004 Applicability language

4. Applicability

4.2 Facilities

4.2.1 Protection Systems for BES Elements, with the following exclusions:

4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

Suggested Requirement Language:

Each Generator Owner that owns a generating Facility that experiences an event resulting in a total capacity derate of or could have resulted in a total capacity derate of:

- 10% or greater than or equal to 20MVA, whichever is greater, for generating resources identified under Inclusion I2 of the BES definition or

- 10% or greater than or equal to 75MVA, whichever is greater, for generating resources identified under Inclusion I4 of the BES definition

for longer than four hours in duration, a start-up failure where the unit fails to synchronize within a specified start-up time, or a Forced Outage for which (i) the apparent cause(s) of the event is due to freezing of the Generator Owner's equipment within the Generator Owner's control, and (ii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2 shall:

Acciona Energy also does not believe designing or retrofitting generation resources to "the documented minimum hourly temperature experienced at its location since 1/1/1975" is a practical or economical approach without applying a statistical analysis.

Likes 0	
Dislikes 0	

Response

Diana Torres - Imperial Irrigation District - 6

Answer	
Document Name	

Comment

The lowest hourly recorded temperature design criteria does not represent true freezing potential for IID units and is problematic. The EOP-012-1 should be revised to allow for an exemption based on an Engineering Analysis.

The reponse to Comment 8 was "Yes"

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

Response #8:

No. Due to the speed at which EOP-011-2 and EOP-012-1 are being implemented, Duke Energy will repeat much of the work performed for EOP-011-2 shortly after it is implemented. From a GO/GOP perspective, it would more cost effective to cancel implementation of EOP-011-2 GO/GOP related Requirements and implement EOP-012-1 when approved.

Response #10:

R1.1: Requirement R1.1 appears to be disproportionate relative to the required minimum hourly temperature data that must be evaluated and retained in perpetuity for each generating unit. For example, assuming an implementation date of 7/1/2024, it is anticipated that Duke Energy will be required to retrieve and maintain in excess of 40 million hourly data records for R1.1 during its initial examination of minimum hourly temperature data. Additionally, the date of 1/1/1975 does not address the accuracy and availability of data or recent documented changes in the climate of North America. The following four primary arguments support modification of the 1/1/1975 date:

(1) R4 as currently written requires that once every five calendar years each GO review its documented minimum hourly temperature developed pursuant to Part 3.1 and “update” its cold weather preparedness plan with the lowest temperature. If a “lower” minimum temperature is experienced after the initial evaluation, R4 will remedy any subsequent need to modify this temperature.

(2) Duke Energy meterologist suggest that the quantity of weather recording sites with reasonably accurate data is much more favorable for the period starting 1991.

(3) A 30 year period for the calculation of climate normals was first adopted by the governing body of international meteorology in the 1930's. The National Weather Service (NWS) continues this practice by using the last 30 years of data to calculate national climate averages. This data can be found in the NWS Climate Normalization Increment Period of 1991-2021.

(4) Climate change data presented by the United States Environmental Protection Agency's website (www.epa.gov), indicates a marked increase in annual average temperatures in the contiguous 48 states beginning around 1990. This would suggest that restricting the historic data to a timeframe of 30 years or less would better reflect climate changes being experienced in North America.

Please consider modifying the R1.1 date of 1/1/1975 date to 1/1/1991.

R1.2: Is the intent of R1.2 to incorporate Newton's Cooling Law in generating unit design freeze protection measures? If no, please define its intent and GO/GOP required actions to achieve compliance.

R1.2/R1.3: Does R1.2 or R1.3 require the collection of meterological data other than ambient dry-bulb temperature (e.g., wind speed/direction and precipitation,)? If yes, please define additional data.

R1.2/R1.3: What methodology(ies), procedures, standards, etc. are suggested to properly evaluate and apply the cooling effects of wind and freezing precipitation? Industry will need assistance from NERC in determining how to perform this analysis given the ambiguous nature of this requirement. Additionally, suggest adding “as necessary” to these phrases.

R1.2/R1.3: Requirements R1.2 and R1.3 use the phrase "generating unit design". Does this phrase imply these requirements only apply to new units during the design process? Since an existing generating unit is based on an existing design, is the intent to include existing units in these Requirements? Additionally, if the intent is to only impact new units in the design phase, consider changing "generating unit design" with "new generation unit design"; if all unit types are included, consider changing the phrase to "new and existing generating unit designs".

R1.3: The R1.3 requirement is nebulous, over-reaching, and not auditable as written (“design shall account for the impacts on operation due to precipitation”). In order to understand the intent and breadth of this Requirement, please consider rewriting this Requirement to state specific and achievable actions. Additionally, is “non-freezing” rain considered precipitation?

R2: Considering the length of time needed to design, construct, and startup “new generating unit(s)”, it may be desirable to clearly define: (a) the compliance phases of a new versus existing generating unit and (b) whether the modification of an existing unit would change its definition and application to a new unit. For example: Utility A is constructing a nuclear unit that has a design phase (which includes “freeze protection measures”) of 2 years and a minimum construction period of 8 years. During its design phase, it is determined that the applicable minimum hourly temperature is -10 F. If a minimum hourly temperature of -20 is experienced during year 7 of its construction period, how would R1.1 and R3.1 apply relative to the “minimum hourly temperature”?

M2: Consider modifying M2 language as follows: …or hardcopy format: Documentation of technical, commercial, or operational constraints”, and” Documentation of five…

R3: It may be desirable to maintain a single Cold Weather Preparedness Plan on a site/plant basis – instead of a unit basis. Consider modifying R3 to read: …for its generating units "or sites": The cold…

R3.4.2: Does R.3.4.2 Bullet 1 decribe the design temperature based on historical minimum hourly temperature (e.g., 1975 to Implementation Date)? If no, please further define.

R3.4.2: Does R.3.4.2 Bullet 3 describe the design cold weather temperature that exist prior to the implementation of any new freese protection measures? If no, please further define. (Note: Does Requirement R3.4.2 Bullet 3 require an engineering analysis to determine the current design cold weather temperature?)

R4.2: Requirement 3.4.2 list three "Generating unit(s) minimum" temperatures (Design, Historical and Current). Requirement 4.2 reads: Review its documented cold weather minimum temperature contained… Consider adding a "s" to temperature as follows: …minimum temperature"s" contained…

Section R4.2: This Section defines "generating unit" as Bulk Electric System Generators. This definition would exclude solar sites since photovoltaic panels are not generators. Consider replacing the word "generator" in this section with "generation sources/resources" or "BES generation sources/resources" if the intent is to include solar.

R6: Does total capacity refer to Net, Gross, Other Total Capacity? Please define or clarify the phrase: …10% of the total capacity of the unit…

R6: Please define or clarify the phrase: …specified start-up time... This is a imprecise phrase since the following attributes are not defined: who specifies start-up time, where is it documented, how is it defined, what is its duration, etc.

R6: Consider clarifying which temperature(s) for R6 applies for the following since three Generating unit(s) minimum temperatures are listed in Part 3.4.2 (Design, Historical and Current): …time of the event are at or above the "temperature" documented in Part 3.4.2 shall…

Q7: Does "Sum of capacities (in MW)" refer to Net, Gross, Other Total Capacity? Please define or clarify the phrase.

Likes 0	
Dislikes 0	

Response

Michael Watt - Oklahoma Municipal Power Authority - 4

Answer	
Document Name	

Comment

I agree with TAPs comments, pasted below:

TAPS appreciates the opportunity to comment on the draft standards, and we thank the SDT for their hard work in developing these important standards on an accelerated timeline. With limited exceptions, we do not disagree with the substance of the proposed standards; we do, however, have some significant concerns regarding clarity and unintended consequences.

R4

Scope of R4.3; overlap between R4.3 and R1.4

We understand that the SDT intends R4.3 to apply only in the case where a GO's lowest temperature pursuant to R3.1 has changed since the last review, since the GO's existing freeze protection measures may not be adequate to meet the new, lower temperature. But the text as written requires a full self-audit of R1 compliance every 5 years regardless of whether the minimum temperature has changed. We suggest a minor edit to clarify the intended scope of R4.3. In addition, as noted above in response to Question 4, the current wording of R4.3 overlaps with the requirements of R1.4 and would lead to duplicative noncompliance; we suggest an edit to avoid that issue.

"Maintenance" of cold weather preparedness plan; possible combination of R4 with R3

R4 seems to set out, at least in part, how a GO "maintains" its plan, as required by R3. To avoid duplication, either the words "and maintain" should be deleted from R3, or R4 should be made a subrequirement of R3, prefaced by language along the lines of "Maintenance of the plan, which shall consist of the following reviews every five years:" Additional subrequirements could be added to ensure that the GO's 5-year review covers all aspects of its cold weather preparedness plan.

R6

Derate threshold

We have both substantive and clarity/consistency concerns regarding R6. With respect to the substance, the choice of a derate of 10% of the unit's capacity as the threshold does not seem to be supported by any technical analysis, and would be unreasonable in the case of small generators. If a derate threshold is retained, the SDT should consider making it "the greater of" some percent of the unit's capacity or a MW value, e.g. "10% of the total capacity of the unit or 10 MW, whichever is greater," and/or tying it to reserve requirements.

Clarifications

"a specified start-up time"

Failure to synchronize "within a specified start-up time" is vague to the point of unenforceability: it *could* mean the minimum start-up time that the GO has communicated to its BA (assuming that every GO has done so), but there is nothing in the proposed text preventing an auditor from deciding that some other "specified time" should have been used. We suggest that "minimum start-up time" be added to the cold weather preparedness plan in R3 (possibly under R3.4.1), and then referenced in R6, i.e. "a start-up failure where the unit fails to synchronize within the start-up time specified in the applicable cold weather preparedness plan."

Other necessary clarifications

The text of R6 is unclear in other ways. In particular, (1) the word "event" is used in different places to mean either (i) a derate, failure to start, or Forced Outage, or (ii) the cause of the derate, failure to start, or Forced Outage; (2) it is syntactically ambiguous whether the two numbered preconditions in R6 ("for which (i) the apparent cause(s) of the event…") must be met with respect to all three types of issue, or only with respect to Forced Outages; and (3) "freezing of equipment" is vague: does it include icing, or only freezing of the liquid components of generation equipment? We propose edits to address the first two concerns, including making R6 an if-then statement with three preconditions; if all three are satisfied, the subrequirements are applicable. This does not change the meaning of the SDT's proposed text; it simply clarifies it by making all three preconditions explicit.

Possible merging of R6 CAP requirements into R1.4

Finally, as noted above in response to Question 4, R6 is duplicative of R1.4; we suggest replacing R6's CAP requirements with a reference to R1.4, leaving just the identification and analysis of events in R6.

Alternative proposals

If the SDT retains a separate CAP requirement in R6, it should at minimum, as suggested in our response to Question 4, clarify in R1 that corrective actions in response to an R6 event are subject only to R6, not R1.4; it should also revise R6.2.6 consistent with the changes to R1.4.4 that we proposed in response to Question 4.

VSLs

Our comments on the VSLs address the appropriateness of the proposed VSLs with respect to the Requirements language as proposed by the SDT; we have not, for the most part, suggested additional conforming changes in line with our suggested revisions to the Requirements.

R1 and R2: percentage of noncompliant units is an inappropriate metric

R1 and R2 have VSLs based on the percent of a GO's units for which it did not comply. This is unfair to smaller entities, who may have only one or two units. It is also not a reasonable metric: a GO with 100 units, that entirely disregarded R1.1-R1.3 with respect to 10 units, would be a Moderate VSL, while a GO with a single unit, for which it met the criteria in R1.1 and R1.2 but not R1.3, would be a Severe VSL. A more reasonable approach with respect to R1.1-R1.3 would be VSLs along the lines of "had freeze protection measures compliant with R1.1 but not R1.2 and/or R1.3," "had freeze protection measures, but measures were not sufficient to meet R1.1-R1.3," "had no freeze protection measures," etc. If the SDT nevertheless retains percentages of units in the VSLs, it must at minimum clarify the denominator for each—we believe that for R1, the intent is the GO's applicable units, and for R2, it is the GO's applicable new units for which it cannot meet the R1 criteria due to technical commercial, or operational constraints. And the SDT would need to clarify the time period over which the R2 percentage is taken—e.g. if a GO has 10 applicable units with R2 constraints, two of which were identified in each year over a five-year period, and it failed to document its determination and the constraints with respect to one of the last two units, is that a Severe VSL (because it was noncompliant with respect to 50% of its applicable units in that year), or Moderate (because it was noncompliant with respect to 10% of its total applicable units, or 10% of the applicable units identified over a 5-year period)?

R1.4: need for Low, Medium, and High VSLs

While R1.1-R1.3 have multiple VSLs (even though those VSLs are based on an inappropriate metric), R1.4 has only a single VSL—Severe—where the GO "did not develop or implement a CAP as required by Requirement R1." This is unreasonable; a GO might develop a CAP but only partially implement it, or develop and implement a partially-compliant CAP, etc. In addition, if R1.4 had a deadline, as we suggest it should in response to Question 4, then VSLs could be based on degrees of lateness.

R2 and R4: unintended ambiguity depending on date of discovery of noncompliance

The VSLs for R2 and R4 do reflect degrees of lateness, but they have another flaw: one possibility for a Severe VSL is "did not complete a review"/"does not have a completed review," while a "High" VSL is "was late by greater than 60 calendar days." But what if the noncompliance is discovered in an audit 50 days after the deadline? Is it a Medium VSL (because it is not yet more than 60 days late) or Severe (because the review isn't (yet) done)? The VSLs for R2 and R4 should be revised so that High has a maximum number of days, and Severe is "more than [x] days" late.

R4: omission of updating of plan from Low, Medium, and High VSLs

The text of Requirement R4 requires GOs to review and, if necessary, update their plans. The Low, Medium, and High VSLs for R4 refer only to completing the required review. The Severe VSL includes "The Generator Owner does not have a completed review. OR The Generator Owner did not update the cold weather preparedness plan." The (likely inadvertent) omission of "updating" from the lower VSLs suggests that being a day late in updating a cold weather preparedness plan is just as bad as being 6 months late. The words "and any necessary update(s)" should be added to Low through High VSLs.

R5: ambiguous application

Because the R5 VSLs are based on the *absolute number* of applicable personnel “at a single generating unit” that haven’t been trained, “or” the *percent* of the GO’s “total” applicable personnel that haven’t been trained, there are plausible scenarios where the appropriate VSL would be unclear, or where a violation could be considered either multiple lower-VSL violations or a single higher-VSL violation. We believe that this problem could be remedied by (1) making the metrics consistent, i.e. either (a) “one applicable personnel; or 5% or less of its total applicable personnel,” or (b) “one applicable personnel at a single generating unit; or 5% or less of applicable personnel at a single generating unit”; and (2) specifying whether to use the greater of, or lesser of, those two options in each case—for example, for GO with a single unit with two applicable personnel, one untrained person (low VSL) would be more than 15% of applicable personnel (severe VSL).

R6: percentage of R6 events is an inappropriate metric

Assuming that R6’s CAP requirement is not moved to R1.4, the VSLs for R6 should differentiate based on whether each required CAP was (1) developed, fully or partially, (2) consistent with some or all of the criteria, and (3) timely (with gradations of lateness), etc. The proposed VSLs are instead based on the percent of a GO’s “total events listed in R6” for which it did not develop a fully-compliant CAP. This is an unreasonable metric, and unfair to smaller entities with a small number of units: A GO that experienced 100 R6 events and did nothing at all with respect to 10 of them would be a Medium VSL, while a GO that experienced one R6 event, for which it developed a partially-compliant CAP, would be a Severe VSL. The SDT should not retain the proposed VSLs for R6, but if it does, it must at minimum indicate over what time period the percentage is calculated—is it one winter season? One calendar year? Some other time period?

Proposed language for R3, R4, and R6

Scope of R4.3; overlap between R4.3 and R1.4

Proposed language

If the lowest temperature established pursuant to Requirement R1 has been updated in the cold weather preparedness plan pursuant to R4.1, review whether its generating units have the freeze protection measures required to operate at the updated lowest temperature. If freeze protection measures must be supplemented or modified as a result of the updated lowest temperature, the requirements of Part 1.4 apply.

“Maintenance” of cold weather preparedness plan; possible combination of R4 with R3

Proposed language

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1. Documented minimum hourly temperature experienced at its location since 1/1/1975 or a lesser period if reliable data is not available to 1975;

3.2. Documented generating unit(s) freeze protection measures based on geographical location and plant configuration;

3.3. Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.4. Generating unit(s) cold weather data, to include:

3.4.1. Generating unit(s) operating limitations in cold weather to include:

3.4.1.1. Capability and availability;

3.4.1.2. Fuel supply and inventory concerns;

3.4.1.3. Fuel switching capabilities; and

3.4.1.4. Environmental constraints.

3.4.2. Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

3.5. Maintenance of the cold weather preparedness plan, which shall consist of the following reviews every five calendar years:

3.5.1. Review the documented minimum hourly temperature developed pursuant to Part 3.1, and update the cold weather preparedness plan with the lowest temperature as necessary;

3.5.2. Review its documented cold weather minimum temperature contained within its cold weather preparedness plan(s) for its generating units, pursuant to Part 3.4.2;

3.5.3. Review whether its generating units have the freeze protection measures required to operate at the lowest temperature established pursuant to Requirement R1 and, if not, implement appropriate modifications per the requirements of Part 1.4.;

3.5.4. Review procedures for annual inspection and maintenance of generating unit(s) freeze protection measures, and update as necessary; and

3.5.5. Review generating unit(s) cold weather operating limitations documented per R3.4.1, and update as necessary.

R6

Proposed language

R6. If (i) a generating unit experiences an event ("event") consisting of (a) a derate of more than 10% of the total capacity of the unit or 10 MW, whichever is greater, for longer than four hours in duration, (b) a start-up failure where the unit fails to synchronize within the start-up time specified in the applicable cold weather preparedness plan, or (c) a Forced Outage; (ii) the apparent cause(s) of the event is freezing of the Generator Owner's equipment within the Generator Owner's control; and (iii) the ambient conditions at the site at the time of the event are at or above the temperature documented in Part 3.4.2, then: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1. No later than 150 days subsequent to the event or by July 1 that follows the event, whichever is earlier, the Generator Owner that owns the affected generating unit shall analyze and document:

6.1.1. A summary of the identified cause(s) for the freezing of equipment where applicable and any relevant associated data; and

6.1.2. A review of applicability to similar equipment at other generating units owned by the Generator Owner.

6.2. Corrective actions in response to the analysis required by R6.1, including new or modified freeze protection measures, are subject to the requirements of Part 1.4 and, if applicable, Part 1.5.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	

Document Name	
Comment	

RE: EOP-011-3: Please consider removing the "Interpretations" section of the standard. Please consider listing the Implementation Plan and Technical Rationale document in the "Associated Documents" section of the standard.

RE: EOP-012-1: Please consider listing the Technical Rationale document in the "Associated Documents" section of the standard. In the Compliance section, please consider if the titles of section 1.1 Compliance Enforcement Authority, 1.2 Evidence Retention, and 1.3 Compliance Monitoring and Enforcement Program should be on their own lines with the details following below, if there is a template for the Compliance section of standards, considering the difference in the layout between EOP-011-3 and EOP-012-1.

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli

Answer	
Document Name	
Comment	

Xcel Energy appreciates the work of the drafting team in addressing the reliability need related to this project. We look forward to supporting the next draft after the team has been able to consider comments.

Likes 0	
Dislikes 0	
Response	

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	
Document Name	
Comment	

TMLP agrees with the comments submitted by Rebecca Baldiwn on behalf of TAPS Group for Question 10.

Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1

Answer	
Document Name	

Comment

We support LPPC's comments. Please reference our response to #4 about a time element and instance exclusion to continuous operations.

Likes 0	
Dislikes 0	

Response

Casey Perry - Casey Perry On Behalf of: Lynn Goldstein, PNM Resources - Public Service Company of New Mexico, 1, 3; - PNM Resources - Public Service Company of New Mexico - 3 - WECC

Answer	
Document Name	

Comment

PNM supports the EOP-011-3 and EOP-012-1 addition comments provided by EEI.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

Minnesota Power has decades of operating experience in extreme cold temperatures with few events impacting reliability. Minnesota Power appreciates the proposed R6 requirement in EOP-012-1, which focuses on evaluating causes of failure due to freezing issues and identifies corrective actions to continuously improve reliability.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	

Capital Power supports the NAGF comments / concerns / suggested revisions related to this question.

Likes 0	
Dislikes 0	
Response	

Mark Spencer - LS Power Development, LLC - 5	
Answer	
Document Name	
Comment	

There is no field to input comments to question #8 (it skips from #7 to #9) on my ballot so I offer the response here.

8. The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.

0 Yes

1 No

Comments:

The proposed requirement of being "capable of continuous operations at the documented minimum hourly temperature experienced at its location since 1/1/1975" imposes reliability requirements that far exceed the system planning standards and performance of the distribution system, and are not coordinated with other factors that may first cause load shedding. We need to take a step back and investigate more thoroughly how the extreme cold weather preparedness requirements match regional planning criteria and flange up with the supply chain elements outside the scope of the Standards that are equally as necessary to generate and deliver electricity. As an example, if a BA plans to a 1-in-10 LOLE and generator weatherization imposes a greater than 1-in 47 LOLE, load shedding due to insufficient capacity, not freezing, would likely occur first. Also, there are many other factors that impact generation availability during extreme cold weather events other than systems freezing. None of these other elements would be cold weather hardened to a similar degree, and power plants that are hardened in accordance with the proposed Standards may be unavailable for reasons outside the scope of the Reliability Standards – i.e., rail, pipeline, or truck deliveries; cooling water supplies; etc. Some resources may reach environmental limitations well before the specified low temperature is reached. It is critical that a more holistic approach to extreme weather performance be taken.

Other concerns are the specified ambient conditions appear overly conservative. Rational arguments can be made for the use of the coldest hourly temperature in the last 47 years as the basis, but not for the performance requirement at this temperature continuously. Creating a synthetic criteria that has not been observed naturally – i.e., the continuous application of the worst assumptions for temperature, precipitation and wind conditions that did not occur concurrently, does not seem reasonable.

In contrast, current freeze protection design takes into account a starting point and ending point, and examines the duration and depth of the extreme condition when specifying freeze protections measures. Mr. Mark Dittus, Black & Veatch, explained this “Time to Freeze” concept during the April 27, 2022 FERC technical conference. As an example, the proposed standard would obligate a generator located near Dallas, TX to be able to operate at -2° F continuously despite the fact the region has experienced only one hour at that temperature in the last 47 years. The proposed standard then goes further and imposes the requirement to “account for the cooling effect of wind” and the “impacts on operations due to precipitation” but offers no guidance on how to estimate the coincidence of these factors. As the temperature decreases the chance of precipitation also decreases, yet the standard tells generators to plan for the lowest observed temperature and precipitation. Notably, there was no recorded precipitation when the mercury dropped to -2° F in Dallas. The proposed standard layers on top of this approach to temperature and precipitation that generators must also account for wind; the wind speed was measured at 5 mph coincident with the temperature plunging to -2° F in Dallas. It is unclear how often these synthetic conditions may actually occur, but it is most assuredly less frequently than once every 47 years, yet the standard requires continuous performance at these conditions.

Compounding these issues is that compliance costs increase non-linearly with temperature. Most freeze protection measures are passive – i.e., insulation, and require naturally-occuring and frequent periods of thawing conditions to offset the prolonged freezing conditions the insulations resists. If the Standards specify continuous, below freezing conditions, passive measures are unsuitable and must be replaced with active measures – e.g., heat trace, space heating, auxiliary boilers, etc. That is, a power plant in Dallas, TX must have heat trace installed on all piping regardless of diameter in order to comply with the Standard. This will necessitate stripping insulation, adding electrical distribution feeders and circuits to handle the higher parasitic loads, and wrapping all pipe with heat trace. The backfeed costs of keeping these circuits energized during cold weather would also be substantial.

While Winter Strom Uri provides important and life-savings lessons, and we agree that enhanced performance standards are necessary, The Report notes that (i) certain generators failed to perform at their design conditions and (ii) other generators were unable to obtain fuel. The former concern may be addressed by better oversight or market design (under the purview of the BAs). The latter concern is outside the scope of this reliability standard, but may be address by the BAs through other means in coordination with implementing exteme cold weather preparedness.

In lieu of attempting to implement a vaguely defined standard that is left to each generator to interpret, we propose that NERC allow the BA’s to define the specification but require that it overlap with the BA’s planning assumptions. For example, if a BA creates load forecasts with 1-in-20 probabilities (i.e., 95th percentile) then the extreme cold weather standard should be slightly more conservative, but not significantly more, than the 1-in-20 year planning assumption. It would also be less prone to interpretation if the ambient conditions were based on weather reporting station(s) identified by the BAs, and the generator would then have to demonstrate to the BA that it is capable of operating at the specified conditions reported by the nearest designated weather station. In the event that there is significant elevation change or distance between the closest designated weather reporting station and the generator then the generator may be required to modify its performance target to local conditions through statistical sampling techniques that bias the weather station conditions. This further eliminates the potential that many generators may not have hourly weather data at their site prior to their construction, let alone back to 1975.

Additional comments for #10:

While the Reliability Standard does require generators to develop cold weather preparedness plans and train personnel on these plans, we offer that the standard could be more explicit and prescriptive. As was observed in 2011 and 2021 many generators had freeze protection installed that simply failed to work properly. We conjecture that if all installed freeze protection measures functioned properly these events would have been reduced in severity. Therefore, the Reliability Standard should require the generators to explicitly develop preventative maintenance plans that are performed at a frequency and in sufficient detail to ensure that installed systems are functioning as they were intended and be included as part of the plan. Additionally, the completed PM records should be maintained as part of the evidentiary record to demonstrate compliance with the standard.

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 Regional Standards Committee

Answer	
Document Name	

Comment

NPCC RSC has concerns with EOP-012, R2, and R2 states once every five years, but the evidence retention period is only 3 years, and GO/GOP are audited every 6+ years. There is a disconnect with the evidence retention period.

For R4, the retention period is: The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4.

All requirements under this standard should have a retention period “since the last audit”.

For Canadian entities, the operation of hydroelectric generating units in cold weather conditions is part of the normal operating conditions. The design, maintenance, and operation of the generating units are done accordingly. For example, the generating units being installed indoors (either in a powerhouse or underground), these units do not require specific freezing measure protection.

Sub requirement 1.2.5.3 and 1.2.5.4 of Requirement 1.2.5 in EOP-011-3 state:

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.

If, for a certain region, there is no provision to minimize the overlap of the circuit because the load is insufficient, how does an entity comply with the requirement?

Sub requirement 1.2.5.1 of Requirement 1.2.5 in EOP-011-3 states:

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

What amount of load should be available for operator-controlled manual load shedding?

Consider removing the Time Horizon and VRF columns in the EOP-011-3 VSL Table.

Requirement R3 in EOP-012-1 reads that “each GO shall implement and maintain one or more cold weather preparedness plans …” whereas R5 refers to “implementing cold weather preparedness plans developed pursuant to R3.”. The SDT should consider revising R3 to include “develop, implement and maintain one or more cold weather preparedness plans”.

As proposed, EOP-011 has the unintended consequence of requiring transmission-only entities to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies. RSC requests that the Standard Drafting Team revise EOP-011 and the Technical Rationale with due consideration to areas of the ERO Enterprise for which the Transmission Operator does not serve as a Distribution Provider nor UFLS-Only Distribution Provider.

Having “Provisions to minimize the overlap of circuits” in 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”, can potentially allow for noncompliance with the coordination with other UFLS programs, required by PRC-006-NPCC-2 (i.e. coordination between the manual and automatic UFLS)

The suggestion is made that the word coordinated should be added to 1.5.2.1, as follow: “Provisions for **coordinated** manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;”

Suggestion is made that the word coordinated should be added to 1.5.2.2, as follow: “**Coordinate the** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for **with the automatic** underfrequency load shed (UFLS) or **automatic** undervoltage load shed (UVLS); and”.

Question 8 Comments:

For Canadian entities, the necessary cold weather practices are already in place. The administrative burden associated with the tasks being required in the standards outweighs the reliability benefits, as we already have a good handle on planning, operations, and maintenance activities in cold (and even extreme cold) weather.

Although RSC abstains from commenting on whether the modifications meet the key recommendations in The Report in a cost effective manner, RSC comments “No” here consistent with comments in response to Question 1. As proposed, EOP-011 has the unintended consequence of requiring RSC and other transmission-only entities to implement provisions that, in fact, Distribution Providers and UFLS-Only Distribution Providers are required to perform in order to mitigate operating Emergencies.

There is little to no benefit to grid reliability by imposing training requirements annually, across the board; this is not a cost effective approach.

The winterization program call-ups task are not knowledge based tasks and do not requires annual refresher for the maintenance personnel to be able to perform the maintenance as required by the maintenance package.

Moreover, for the operating personnel's annual training, a suggestion is made to have the operator's training included as part of the PER-006-1 Specific Training for Personnel, Requirement R1.

Likes 0	
Dislikes 0	
Response	

Michele Richmond - Texas Competitive Power Advocates - NA - Not Applicable - Texas RE	
Answer	
Document Name	Additional TCPA Comments on NERC Weatherization 6-20-22.docx
Comment	
Additional TCPA Comments attached	
Likes 0	
Dislikes 0	
Response	

Donna Johnson - Oglethorpe Power Corporation - 5	
Answer	
Document Name	
Comment	

: The requirements should be re-arranged. Current R1 should be R2, current R3 should be R1, and current R2 should be R3, then so on… If done that way, you would not have to re-state what is currently in R1.1. After the shuffle: R2.1 would say: “Each generating unit shall be designed and maintained to be capable of continuous operations according to the temperature designated under R1.1” (R3.1 now).

Agree with ACES comment: “In regards to determining the minimum hourly temperature to which generating units should be designed and maintained to be capable of continuous operations: was there any consideration of utilizing future forecasted minimum temperature data rather than, or in addition to, historical temperature data?”	
Likes 0	
Dislikes 0	
Response	
Meaghan Connell - Public Utility District No. 1 of Chelan County - 5, Group Name PUD No. 1 of Chelan County	
Answer	
Document Name	
Comment	
CHPD agrees with LPPC's comments.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 5, 6; Jennifer Flandermeyer, Evergy, 1, 3, 5, 6; Marcus Moor, Evergy, 1, 3, 5, 6; - Alan Kloster	
Answer	
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #8 and their addtiional comments for this section. Evergy believes that the Project 2021-07 SDT needs to carefully consider the possibility that these requirements will have the unintended consequence of driving some Generator Owners to decide that the cost of retrofit is too high and that it would be in the entity’s best interest to retire existing generation rather than retrofit a unit to prevent freezing at the lowest temperature since 1975. Given the current concerns about capacity shortages across the U.S., NERC should not unintentionally provide further economic justification for Generator Owners to retire existing dispatchable generation that could perform adequately in extreme, non-freezing weather events necessary to support grid reliability.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	

Answer	
Document Name	

Comment

Comments: MidAmerican supports EEI's additional comments regarding EOP-011-3 and EOP-012-1.

MidAmerican recommends the SDT better define documented minimum hourly temperature if this is the term that the SDT is using. After a review of reliable weather sources, some data is missing and therefore MidAmerican understands it has the discretion to ignore missing data and choose the lowest reliable minimum hourly temperature for the nearest city.

To simplify this, MidAmerican recommends replacing "hourly" with the terminology from the technical rationale, using the "lowest recorded ambient temperature for the nearest city for which historical weather data is available". A review of the NOAA website shows daily minimums are available back to 1/1/1975. The use of daily meets the reliability objectives of the new NERC standard (as it wasn't the single lowest temperature that caused the loss of generation, rather it was sustained cold weather). NERC zero defect standard auditing could result in administratively burdensome costs if "hourly" is literally interpreted to mean 24 readings per day back to 1975, especially for those entities with large generating fleets in a diverse geographic area.

Hourly data may be available from 3rd party weather data aggregators or commercial weather enterprises; however, this data should come from trusted, government sources, as the reliability of the data coming from 3rd party sources cannot be easily verified.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Submitted on behalf of Exelon (Segments 1 & 3)

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	
Document Name	

Comment

In regards to determining the minimum hourly temperature to which generating units should be designed and maintained to be capable of continuous operations: was there any consideration of utilizing future forecasted minimum temperature data rather than, or in addition to, historical temperature data?

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

SIGE recognizes the work that the SDT has undertaken to address the first 4 requirements of the joint Report. SIGE also is appreciative of the opportunity to provide comments for consideration to this team.

While SIGE is generally in support of additionally criteria to improve reliability and protect the grid from extreme weather conditions, SIGE does have requests additional clarity on the following items:

- For EOP-012-1, what is the scope of equipment included in the definition of a “generating unit” in a technical sense EOP-012-1 R1. For example, does it include high or low side of the GSU, transmission equipment (e.g., transmission lines above the power station), etc. And how does the assessment consider equipment housed in a heated buildings?
- Additionally, what is the intended scope of “generating unit” from a renewable resource standpoint – specifically solar? Is it a singular inverter or the solar field as a whole plant? If it was intended to be wholistic, SIGE recommends the use of “generating plant” or other more expansive language.
- Are fuel issues such as frozen coal or gas storage/valve issues considered an operational constraint or is fuel supply viewed wholistically as part of the ‘generating unit’? If the latter, that could have a significant impact on GOs regarding R1 and R6.
- Is R1.1, R1.2, R1.3 focused on unit design or freeze protection measures? The current language suggests unit design. SIGE suggests adding the term “freeze protection” or “freeze protection measures” to the sub requirement language for more clarity.

***C*omment 8 is missing from the SBS system. SIGE provides the following response to Comment 8.**

*The SDT proposes that the modifications in **EOP-011-3** and the newly drafted **EOP-012-1** meet the key recommendations in The Report in a cost-effective manner. 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.*

No; SIGE believes the generating unit should be reasonably expected to continuously operate at the generating plant’s minimum design temperature, historical operating temperature, or current cold weather performance temperature determined by an engineering analysis (per R3.4.2). The use of the lowest one-hour temperature since 1975 for determining minimum operating criteria is not likely achievable for older generation plants and doesn’t account for changing weather patterns. The resulting implications could be modifications that are too expensive or onerous which may unintentionally lead to more units retiring earlier and/or more units opting for (R1.4.4) constraints which would have a negative effect or no beneficial impact on the reliability of the grid.

Likes 0	
Dislikes 0	

Response

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1, Group Name OGE Energy - Oklahoma Gas and Electric Co.

Answer	
Document Name	

Comment

For Question 8 (missing on form): Oklahoma Gas and Electric agrees with and endorses comments as submitted by EEI Reliability Technical Committee (RTC)

Likes 0	
Dislikes 0	

Response

Jennifer Blair - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC, Group Name PPL NERC Registered Affiliates

Answer	
Document Name	

Comment

PPL NERC Registered Affiliates support EEI comments on Question 10.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Consider adding requirements or technical rationale document language to address utilities that may own generating units in different climates (northern utilities may require vastly different freeze protection than southern utilities).

Question 8 comment: Please provide some clarification on what constitutes appropriate cost effective manner. What return on investment is needed to meet this measure?	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Dwanique Spiller On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Dwanique Spiller	
Answer	
Document Name	
Comment	

NV Energy supports EEI's additional comments regarding EOP-011-3 and EOP-012-1.

NV Energy recommends the SDT better define documented minimum hourly temperature if this is the term that the SDT is using. After a review of reliable weather sources, some data is missing and therefore NV Energy understands it has the discretion to ignore missing data and choose the lowest reliable minimum hourly temperature for the nearest city.

To simplify this, NV Energy recommends replacing "hourly" with the terminology from the technical rationale, using the "lowest recorded ambient temperature for the nearest city for which historical weather data is available". A review of the NOAA website shows daily minimums are available back to 1/1/1975. The use of daily meets the reliability objectives of the new NERC standard (as it wasn't the single lowest temperature that caused the loss of generation, rather it was sustained cold weather). NERC zero defect standard auditing could result in administratively burdensome costs if "hourly" is literally interpreted to mean 24 readings per day back to 1975, especially for those entities with large generating fleets in a diverse geographic area.

Hourly data may be available from 3rd party weather data aggregators or commercial weather enterprises; however, this data should come from trusted, government sources, as the reliability of the data coming from 3rd party sources cannot be easily verified.

Likes 0	
Dislikes 0	
Response	
Hillary Dobson - Colorado Springs Utilities - 3	

Answer	
Document Name	
Comment	

CSU supports LPPC's comments.

Likes 0	
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3

Answer	
Document Name	
Comment	

Pertaining to Question 8, agree with comment supplied by the U.S. Bureau of Reclamation.

To reiterate, the standard should be focused on those generation types proven to have problems with cold weather operation. The reliability gap the SAR addresses is not a widespread issue over the United States and Canada. It should be clear that generation interconnection transmission Facilities including supporting substations and stations are not applicable.

Likes 0	
Dislikes 0	
Response	

Daniel Mason - Portland General Electric Co. - 6, Group Name PGE FCD

Answer	
Document Name	
Comment	

- **Q8:** The SDT proposes that the modifications in EOP-011-3 and the newly drafted EOP-012-1 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.

A8: Yes, as long as Generator Owners retain the ability to determine corrective actions based upon factors which include the economic viability of the required plant investments.

- **Q10:** Portland General Electric Company also supports the additonal comments for EOP-011-3 and EOP-012-1 provided by EEI.

Likes 0	
Dislikes 0	

Response

Jun Hua - Austin Energy - 4

Answer	
Document Name	

Comment

I support comments made by Michael Dillard, Austin Energy, Segment 5

Likes 0	
Dislikes 0	

Response

Whitney Wallace - Calpine Corporation - 5 - WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

Calpine agrees with and incorporates by reference the comments provided by TCPA for this inquiry. Calpine also agrees with Luminant's comments that a Corrective Action Plan should be required no later than 150 days subsequent to an event, regardless of the month in which an event occurred.

Response for Question 8: No. Calpine agrees that EOP-011-3 and EOP-012-1 should meet the key recommendations in The Report "in a cost effective manner," but disagrees that that SDT meets these recommendations as currently drafted, specifically with regard to Key Recommendation #2 (cost recovery). In fact, this recommendation is not addressed at all in the SDT, which is particularly problematic for generators operating in the competitive areas of ERCOT and who do not have guaranteed cost recovery through a captive rate base, as alluded to elsewhere in these comments. Calpine also agrees with Luminant that generators operating in ERCOT are facting significant costs related to new weatherization requirements that will soon be adopted by the Public Utility Commission of Texas, and that the current ERCOT market design reforms under consideration do not contemplate cost recovery for compliance with these weatherization requirements. Moreover, even outside of ERCOT, generators are not guaranteed full cost recovery through their regulated rates. Compliance with EOP-012-1 should be tied to the availability of a cost recovery mechanism in the marketplace. If there is no provision available for cost recovery, Calpine agrees with TCPA that compliance with EOP-012-1 should be deferred until a suitable cost recovery mechanism is available to the generator.

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	
Comment	

No additional comments.

Likes 0	
Dislikes 0	
Response	

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	2021-07 Initial Ballot_EOP-012-1_clean_051922 (EGP Comments Final).docx
Comment	

- It is recommended that the term "freeze" within the phrase "freeze protection measure" be clearly defined as *the ambient temperature below water freezing point of 32F*. Without this definition, there could be confusion on how the term is applied as it relates to cold weather preparedness as freezing is not consistently and reliably measurable with clear criteria. There are many variables that cause freezing of equipment and that impact operations such as temperature, humidity and surface material. Due to these variables, the term used by itself, does not provide a clear criteria for Generators to apply. Defining this term facilitates clear criteria for implementation.
- The term generating unit causes confusion in how the standard applies to renewable resources. Although an attempt to clarify is provided, the term generating unit refers to each and every individual turbine or invertor. The revision recommended in the attached edits provided is adopted from PRC-024 and uses the same approach as to how this issue was resolved in that standard. *See section 4.2 in the attached for edits.*
- In R1.1 the use of the phrase "continuous operations" is problematic for variable energy resources that are dependent on the wind or sun to generate and therefore are considered intermittent. *See R1.1 in the attached for edits.*
- Generator Owners and Operators should not be required to deploy measures that are not based on industry standards or engineering best practices. It is suggested to clarify this in R3 of the draft as well as this should also be clarified in the rational. *See R3 in the attached for edits.*
- The 10% derate threshold could cause corrective action plans for events that do not impact the Bulk Electric System. A possible solution is to adopt the same approach used in PRC-004 where misoperations that affect an aggregate nameplate rating of less than or equal to 75MVA of BES facilities are excluded. *See R6 in the attached for edits.*
- In addition, Corrective Action Plans should focus on ambient temperature criteria as this is the basis of the operating envelope of a generating resource. This criteria is clearly defined and therefore can be clearly implemented and evaluated. Freezing as it applies to equipment operation is not measurable and can have many variables such as temperature, humidity and surface material. Including freezing as one of the initators for a CAP presents unclear criteria due to the many variables that could or could not apply. It is recommended that accounting for the impact of precipitation freezing issues within the Generators control is already covered in R1.3 and the Corrective Action Plan in the subsequent 1.4 and therefore should not be the initiator of another CAP in R6. *See R6 in the attached for edits.*
- Edits provided clarify that capacity is AC power generating capacity helps make this requirement more accurate for solar facilities. Also clarifying that the threshold applies to a derate involving available generating units takes into consideration when solar farms are online but not producing at night. *See R6 in the attached for edits.*
- Lastly consideration for safety of personnel during extreme cold weather events should be mentioned. *See R6 in the attached for edits.*

Please see the attached file for more information on how the above suggestions can be implemented.

Likes 0	

Dislikes 0	
Response	
Rebecca Baldwin - Transmission Access Policy Study Group - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	TAPS proposed language Q10.docx
Comment	

TAPS appreciates the opportunity to comment on the draft standards, and we thank the SDT for their hard work in developing these important standards on an accelerated timeline. With limited exceptions, we do not disagree with the substance of the proposed standards; we do, however, have some significant concerns regarding clarity and unintended consequences.

R4

Scope of R4.3; overlap between R4.3 and R1.4

We understand that the SDT intends R4.3 to apply only in the case where a GO's lowest temperature pursuant to R3.1 has changed since the last review, since the GO's existing freeze protection measures may not be adequate to meet the new, lower temperature. But the text as written requires a full self-audit of R1 compliance every 5 years regardless of whether the minimum temperature has changed. We suggest a minor edit to clarify the intended scope of R4.3. In addition, as noted above in response to Question 4, the current wording of R4.3 overlaps with the requirements of R1.4 and would lead to duplicative noncompliance; we suggest an edit to avoid that issue.

"Maintenance" of cold weather preparedness plan; possible combination of R4 with R3

R4 seems to set out, at least in part, how a GO "maintains" its plan, as required by R3. To avoid duplication, either the words "and maintain" should be deleted from R3, or R4 should be made a subrequirement of R3, prefaced by language along the lines of "Maintenance of the plan, which shall consist of the following reviews every five years:" Additional subrequirements could be added to ensure that the GO's 5-year review covers all aspects of its cold weather preparedness plan.

R6

Derate threshold

We have both substantive and clarity/consistency concerns regarding R6. With respect to the substance, the choice of a derate of 10% of the unit's capacity as the threshold does not seem to be supported by any technical analysis, and would be unreasonable in the case of small generators. If a derate threshold is retained, the SDT should consider making it "the greater of" some percent of the unit's capacity or a MW value, e.g. "10% of the total capacity of the unit or 10 MW, whichever is greater," and/or tying it to reserve requirements.

Clarifications

"a specified start-up time"

Failure to synchronize "within a specified start-up time" is vague to the point of unenforceability: it could mean the minimum start-up time that the GO has communicated to its BA (assuming that every GO has done so), but there is nothing in the proposed text preventing an auditor from deciding that some other "specified time" should have been used. We suggest that "minimum start-up time" be added to the cold weather preparedness plan in R3 (possibly under R3.4.1), and then referenced in R6, i.e. "a start-up failure where the unit fails to synchronize within the start-up time specified in the applicable cold weather preparedness plan."

Other necessary clarifications

The text of R6 is unclear in other ways. In particular, (1) the word "event" is used in different places to mean either (i) a derate, failure to start, or Forced Outage, or (ii) the cause of the derate, failure to start, or Forced Outage; (2) it is syntactically ambiguous whether the two numbered preconditions in R6 ("for which (i) the apparent cause(s) of the event…") must be met with respect to all three types of issue, or only with respect to Forced Outages; and (3) "freezing of equipment" is vague: does it include icing, or only freezing of the liquid components of generation equipment? We propose edits to address the first two concerns, including making R6 an if-then statement with three preconditions; if all three are satisfied, the subrequirements are applicable. This does not change the meaning of the SDT's proposed text; it simply clarifies it by making all three preconditions explicit.

Possible merging of R6 CAP requirements into R1.4
Finally, as noted above in response to Question 4, R6 is duplicative of R1.4; we suggest replacing R6's CAP requirements with a reference to R1.4, leaving just the identification and analysis of events in R6.

Proposed text for R3, R4, and R6 is attached in redline and clean form.

Alternative proposals
If the SDT retains a separate CAP requirement in R6, it should at minimum, as suggested in our response to Question 4, clarify in R1 that corrective actions in response to an R6 event are subject only to R6, not R1.4; it should also revise R6.2.6 consistent with the changes to R1.4.4 that we proposed in response to Question 4.

VSLs
Our comments on the VSLs address the appropriateness of the proposed VSLs with respect to the Requirements language as proposed by the SDT; we have not, for the most part, suggested additional conforming changes in line with our suggested revisions to the Requirements.

R1 and R2: percentage of noncompliant units is an inappropriate metric
R1 and R2 have VSLs based on the percent of a GO's units for which it did not comply. This is unfair to smaller entities, who may have only one or two units. It is also not a reasonable metric: a GO with 100 units, that entirely disregarded R1.1-R1.3 with respect to 10 units, would be a Moderate VSL, while a GO with a single unit, for which it met the criteria in R1.1 and R1.2 but not R1.3, would be a Severe VSL. A more reasonable approach with respect to R1.1-R1.3 would be VSLs along the lines of "had freeze protection measures compliant with R1.1 but not R1.2 and/or R1.3," "had freeze protection measures, but measures were not sufficient to meet R1.1-R1.3," "had no freeze protection measures," etc. If the SDT nevertheless retains percentages of units in the VSLs, it must at minimum clarify the denominator for each—we believe that for R1, the intent is the GO's applicable units, and for R2, it is the GO's applicable new units for which it cannot meet the R1 criteria due to technical commercial, or operational constraints. And the SDT would need to clarify the time period over which the R2 percentage is taken—e.g. if a GO has 10 applicable units with R2 constraints, two of which were identified in each year over a five-year period, and it failed to document its determination and the constraints with respect to one of the last two units, is that a Severe VSL (because it was noncompliant with respect to 50% of its applicable units in that year), or Moderate (because it was noncompliant with respect to 10% of its total applicable units, or 10% of the applicable units identified over a 5-year period)?

R1.4: need for Low, Medium, and High VSLs
While R1.1-R1.3 have multiple VSLs (even though those VSLs are based on an inappropriate metric), R1.4 has only a single VSL—Severe—where the GO "did not develop or implement a CAP as required by Requirement R1." This is unreasonable; a GO might develop a CAP but only partially implement it, or develop and implement a partially-compliant CAP, etc. In addition, if R1.4 had a deadline, as we suggest it should in response to Question 4, then VSLs could be based on degrees of lateness.

R2 and R4: unintended ambiguity depending on date of discovery of noncompliance
The VSLs for R2 and R4 do reflect degrees of lateness, but they have another flaw: one possibility for a Severe VSL is "did not complete a review"/"does not have a completed review," while a "High" VSL is "was late by greater than 60 calendar days." But what if the noncompliance is discovered in an audit 50 days after the deadline? Is it a Medium VSL (because it is not yet more than 60 days late) or Severe (because the review isn't (yet) done)? The VSLs for R2 and R4 should be revised so that High has a maximum number of days, and Severe is "more than [x] days" late.

R4: omission of updating of plan from Low, Medium, and High VSLs
The text of Requirement R4 requires GOs to review and, if necessary, update their plans. The Low, Medium, and High VSLs for R4 refer only to completing the required review. The Severe VSL includes "The Generator Owner does not have a completed review. OR The Generator Owner did not update the cold weather preparedness plan." The (likely inadvertent) omission of "updating" from the lower VSLs suggests that being a day late in updating a cold weather preparedness plan is just as bad as being 6 months late. The words "and any necessary update(s)" should be added to Low through High VSLs.

R5: ambiguous application
Because the R5 VSLs are based on the absolute number of applicable personnel "at a single generating unit" that haven't been trained, "or" the percent of the GO's "total" applicable personnel that haven't been trained, there are plausible scenarios where the appropriate VSL would be unclear, or where a violation could be considered either multiple lower-VSL violations or a single higher-VSL violation. We believe that this problem could be remedied by (1) making the metrics consistent, i.e. either (a) "one applicable personnel; or 5% or less of its total applicable personnel," or (b) "one applicable personnel at a single generating unit; or 5% or less of applicable personnel at a single generating unit"; and (2) specifying whether to use the greater of,

or lesser of, those two options in each case—for example, for GO with a single unit with two applicable personnel, one untrained person (low VSL) would be more than 15% of applicable personnel (severe VSL).

R6: percentage of R6 events is an inappropriate metric
Assuming that R6's CAP requirement is not moved to R1.4, the VSLs for R6 should differentiate based on whether each required CAP was (1) developed, fully or partially, (2) consistent with some or all of the criteria, and (3) timely (with gradations of lateness), etc. The proposed VSLs are instead based on the percent of a GO's "total events listed in R6" for which it did not develop a fully-compliant CAP. This is an unreasonable metric, and unfair to smaller entities with a small number of units: A GO that experienced 100 R6 events and did nothing at all with respect to 10 of them would be a Medium VSL, while a GO that experienced one R6 event, for which it developed a partially-compliant CAP, would be a Severe VSL. The SDT should not retain the proposed VSLs for R6, but if it does, it must at minimum indicate over what time period the percentage is calculated—is it one winter season? One calendar year? Some other time period?

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1

Answer	
Document Name	

Comment

In EOP-011, the term 'critical load' should be limited to load critical to the Bulk Electric System. Currently, regarding 'critical loads', the associated Technical Rationale states, 'critical loads which may be essential to the integrity of the electric system, public health, or the welfare of the community.' However, since this is a NERC Reliability Standard, we suggest limiting EOP-011 use of critical load to loads to loads which may be essential to the integrity of the electric system.

As a suggestion, **R1.2.5.2** could be changed to: 'should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical loads. (i.e., 'load essential to the integrity of the electric system')

Also, the Technical Rationale should be revised to acknowledge that there are other types of loads are critical but for for human safety or welfare.

GO/GOPs not TOPs should be required to provide the gas infrastructure that is necessary to run their plants to their associated DPs. DPs then can be required to pass the identified circuits to the TOPs.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Tom Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	
Document Name	

Comment

Response to Question #8:

The SRC's review of EOP-012-1 (as currently proposed) is a minimal proposal that does not allow for a degree of consistency across the generation fleet in a given area, including the conditions the generating units would need to retrofit for. As a result, EOP-012-1 does not fully meet the intent behind the standard and the FERC/NERC Report.

(Please note: ERCOT abstains from the SRC comments to Question #8. ERCOT to provide separate comments in response to this question.)

Response to Question #10

The SRC requests the *following additions to EOP-012-1* and is meant to ensure the entities performing the Operational Planning Analysis, Real-time monitoring, and Real-time Assessments, as required by IRO-010-4 and TOP-003-5, have accurate and up-to-date information to ensure reliable operations. There is also a need for this data in performing planning studies and assessments to ensure accurate modeling since the improvements are not required to be implemented for an extended period of time The SRC recommends a template for the GOs to update annually that is prepopulated with the applicable entities (via the notifications below) and provided to NERC for dissemination. This would ease the administrative burden of the GOs and provide the notified entities with consistent data.

R1.4.5. A notification to the applicable Regional Entity, Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator of any CAP and its details.

R2.3. A notification to the applicable Regional Entity, Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator of any constraints and the supporting determination.

R3.4.3 A notification to its applicable Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator of the generating unit cold weather Preparedness plan and details as described in R3.1 through 3.4.

R4.4. A notification to the applicable Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator of any changes identified.

R6.1.1. This CAP to be communicated to the applicable Reliability Coordinator, Balancing Authority, Planning Coordinator, Transmission Planner and Transmission Operator.

The ISO/RTO Council Standards Review Committee (IRC SRC) would like to take this opportunity to thank the Standard Drafting Team for all their hard work and attention to this Project. Your dedication to this Project is sincerely appreciated.

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	EOP-012 redlines ERCOT for submittal.docx

Comment

Q8. ERCOT agrees that certain elements of the proposed standard may meet the recommendations in the Report in a cost-effective manner, but disagrees that some elements—such as the broad exemption language proposed in part 1.4.4—are consistent with the recommendations in the Report. Recommendation 1f in the FERC/NERC Report does not contemplate any sort of broad exception, although ERCOT agrees that a narrow exception to avoid retirements is helpful. ERCOT also agrees that a location-specific standard is appropriate

Q10. ERCOT supports the SRC comments provided in response to this question that address the notification to certain entities of the CAP and its details, including operational limitations, and expected time to resolve. ERCOT encourages a thoughtful and efficient process to achieve this awareness.

In addition to the changes to R1, R4, and R6 and the creation of new R7 (CAP) and R8 (exemptions) ERCOT proposed in response to Question 4, and the removal of R2 proposed in response to Question 5, ERCOT also proposes the following changes to R3 and R5:

ALTERNATE LANGUAGE PROPOSED (REDLINES PROVIDED IN ATTACHED DOCUMENT)

R3: ERCOT proposes the cold weather preparedness plan be reviewed periodically, at least once every five years, to provide the opportunity to update details and evaluate the ongoing effectiveness of its measures.

R3: The information included within the plan should be provide the same detail for each generating unit

R3.1: The plan should document the temperature initially determined in R1 and periodically updated in R4.

R3.2: The freeze protection measures should be appropriate to meet the temperature documented in R3.1, which considers unit location.

R5: ERCOT recommends changing "its" to "the" in the phrase "its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s)," as the relevant personnel may not be employees or contractors of the entity providing the training.

Likes 0	
Dislikes 0	

Response

Sam Nietfeld - Public Utility District No. 1 of Snohomish County - 5

Answer	
Document Name	

Comment

Question 8: Yes

Question 10 Comments: SNPD supports comments submitted by LPPC and Tacoma Power. However, regarding requirements 1.1, 1.2, and 1.3, SNPD believes it will be difficult to prove compliance. Generator O&M manuals do not normally have a minimum continuous temperature rating, so evidence that the generating unit has been designed to be capable of operating down to a specifically defined temperature will be extremely difficult to achieve. Additionally, with the maintenance requirement, it will be difficult to present evidence to prove that maintenance performed on a generating unit will assure that it can operate down to a specifically defined temperature. In summary, SNPD is stating that it is unclear what evidence could be provided to an auditor to prove that our generators have been designed and maintained to continuously operate at a documented minimum hourly temperature.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	
Document Name	

Comment

LCRA agrees with the comments submitted by the North American Generator Forum.

Likes 0	
Dislikes 0	

Response

James Baldwin - Lower Colorado River Authority - 1

Answer	
Document Name	

Comment

LCRA agrees with the comments submitted by the North American Generator Forum.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 5

Answer	
Document Name	

Comment

We support LPPC’s comments. Please reference our response to #4 about a time element and instance exclusion to continuous operations.

Likes 0	
Dislikes 0	

Response

Ashley Scheelar - TransAlta Corporation - 5

Answer	
Document Name	

Comment

Question 8 Comments: Our responses is “No-do not agree”. TransAlta supports the comments of the U.S. Bureau of Reclamation for question 8. Reclamations comments are provided again here: "*The proposed modifications are not cost effective because they universally apply a compliance burden to solve a problem that exists only in a limited geographic area and that is limited to certain types of generation facilities. Further, the proposed ability for Generator Owners to limit the scope of their own applicability (i.e., use of “as defined by the Generator Owner”) precludes the implementation of meaningful change.]*"

Question 10 Comments:

TransAlta provides the following comments for the SDT to consider:

- There is certainly a need for requirements to be in place to address the events of winter storm of February 2021. However, there are generators that are faced with the cost and administrative burden these standards present with little or no reliability benefit to the regions they operate in.

- There are many parts of the EOP-012-1 standard where there is the possibility of varying interpretation for generators and the entities monitoring and enforcing these standards. For example, the data requirements from section 3.4.2 “Historical operating temperature”. I will present a hypothetical example based on my current understanding of the wording: Let’s say I can only produce historical operating temperature data for the generator since 2016. Would an auditor interpret then that I need to obtain an engineering study in place of that limited data set? There are multiple other scenarios related to this particular sub requirement that are subject to interpretation.

- TransAlta requests that the SDT reconsider the yearly requirement for training and instead keep the current wording “Awareness training on the roles and responsibilities of site personnel contained in the cold weather preparedness plan”. The knowledge being conveyed may not be beneficial to those receiving it, especially not on a yearly basis. I will highlight this point with an example: The way we implement training/awareness requirements is typically through a Learning Management System. The best way to implement training is to select a job-code or codes so that all individuals with that job code will automatically receive the training upon starting a role. This is beneficial when personnel changes occur as there is no need for a manual process to review and ensure each new employee is assigned training. To manually manage this would be impossible with a fleet of our size. In all cases where we apply this type of training (communications, protection systems), it makes sense to have a standard to require training as the knowledge is valuable to all those employees with a job code receiving the training. In the case of EOP-012-1, we would have to have potentially hundreds of maintenance staff trained on something only a few individuals at site are responsible for.

Likes 0	
Dislikes 0	

Response

Comments received by: Jeanne Kurzynowski – CMS Energy

Question 1 – Yes
Comments:
In many cases, UFLS and UVLS are implemented on the distribution system, and thus the TOP may not have available detailed information to reflect these in their manual load shedding operations.

Question 2 – Yes
Comments:
The Standard does not currently require the BA to determine the winter season. A new requirement should be added to ensure the BA provides the seasons to the GOs in its footprint. Suggested language for the Requirement: "The Balancing Authority shall determine the winter season for its footprint and shall inform each GO in its footprint of its determination, by [date] of each year for the ahead winter season commencing in that calendar year.

Question 3 – Yes
Comments: No comments

Question 4 – Yes
Comments:
The year 1975 pre-dates modern weather forecasting and recording capabilities. If desired to extend the monitoring period to that extent, we suggest that the requirement instead specify the minimum hourly temperature at the nearest National Weather Service location. Existing generating units should be required to analyze their designed operation parameters using the freeze protection factors to identify any cold weather limitations based on historic operations dating back to 1975, then develop a time limited Corrective Action Plan. Requirement 1 is an overreach of the Federal Power Act because it requires existing facilities to add equipment or retrofit its facilities.

Question 5 – Yes
Comments:
A declaration that the GO cannot meet the constraints is good, but the Requirement does not specify to whom the declaration must be made. Is it simply a compliance document, or should the requirement specify that the impacted BA(s) be notified of the constraint?

Question 6
Comments: Section 1600

Question 7 –
Comments: No comments

Question 8 – No
Comments:
The Standard is a gross overreach of Federal power. The costs for implementing the Changes to EOP-011-3 and EOP-012-1 will be mitigated through an extended implementation plan and through the suggested adjustments to the requirements of the Standards.

Question 9 – No
Comments:
The entirety of Standard EOP-012-1 should have a 5 year implementation plan. The Generator Owners will need sufficient time to develop compliant procedures and practices. Further, the scheduling and financing of modifications will require greater than 18 months.

Question 10

Comments: While the proposed standards provide criteria to guide GO/GOP to implement cold-weather operating capabilities, there is no requirement that the generators actually operate properly during cold weather. Without a results-based requirement that the generators actually operate properly in these conditions (e.g. a compliance violation should they not), the standards fall short