Comment Report

Project Name:	2023-07 Transmission Planning Performance Requirements for Extreme Weather | Draft 3
Comment Period Start Date:	10/7/2024
Comment Period End Date:	10/21/2024
Associated Ballots:	2023-07 Transmission Planning Performance Requirements for Extreme Weather Implementation Plan AB 3 OT 2023-07 Transmission Planning Performance Requirements for Extreme Weather TPL-008-1 AB 3 ST

There were 66 sets of responses, including comments from approximately 156 different people from approximately 101 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Requirement R1 requires Planning Coordinators (PCs) to identify their zone in the map included in Attachment 1. Do you agree with the zones identified on this map? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. The DT updated Requirements R3 – R4 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. The DT updated Requirements R7 – R8 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. The DT updated Requirements R9 – R11 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

7. Provide any additional comments for the 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
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO

					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	Helen Lainis	IESO	2	NPCC
					Keith Jonassen	ISO-NE	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	SPP	2	MRO
					Elizabeth Davis	PJM	2	RF
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
					John Nierenberg	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
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Public Utility District No. 1	Joyce Gundry	3		CHPD	Rebecca Zahler	Public Utility District No. 1	5	WECC

of Chelan County						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
					Tamarra Hardie	Public Utility District No. 1 of Chelan County	6	WECC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
National Grid USA	Michael Jones	1		National Grid	Michael Jones	National Grid USA	1	NPCC
					Brian Shanahan	National Grid USA	3	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC

Randy Buswell	Vermont Electric Power Company	1	NPCC
James Grant	NYISO	2	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC

					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Nicolas Turcotte	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Erin Cullum	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO

					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Mason Favazza	Southwest Power Pool Inc	2	MRO
					Sherri Maxey	Southwest Power Pool Inc.	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC

1. Requirement R1 requires Planning Coordinators (PCs) to identify their zone in the map included in Attachment 1. Do you agree with the zones identified on this map? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with the modifications to R1 that clarify the responsibilities to be identified between the PC and TP, and that require the Extreme Temperature Assessment (ETA) to be completed once every five years. Identification of zones is required in Requirement R2 rather than R1. LG&E/KU agrees with the content of Attachment 1 and the identification of zones according to the table (not map). LG&E/KU notes that the question in this comment form was not updated to reflect changes made to the standard just before the comment period (namely, zones being identified in Requirement R2 and the table of Attachment 1 controlling rather than the table).	
Likes 0	
Dislikes 0	
Response	

Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	
Comparing the table and map is confusing. There are 20 regions shown in the map and 17 in the table; it is not clear why there is a discrepancy. In addition, the map shows the Quebec colored region as part of Eastern Canada which is different than the table, which separates Quebec and Ontario.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Many of the zones are very big, often including a large north-to-south range, such that a single heat or cold benchmark event cannot adequately cover all locations within a zone. Consider MISO in particular – can a single criterion suffice for Minnesota and Louisiana?	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's response, which state: In general, EEI member companies see some value in retaining the maps included in the TPL-008-1, however, we remain concerned that the temperature regions as proposed in those maps (and elsewhere) are in a number of cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, EEI does not agree that maintaining disconnected parts of SERC and PJM into the broader SERC and PJM temperature zones makes any sense. For this reason, we do not support the temperature zones as currently proposed and ask that they be modified. To address our concerns, we suggest at a minimum that 1) SPP and MISO both be split into a north and south region, and 2) the disconnected portions of SERC and PJM be included into zones that more closely align with their temperature regions.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
The Requirement R1 language doesn't refer to zones. Please see our comments below to question 2.	
Likes 0	
Dislikes 0	
Response	

Helen Lainis - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

The IESO does not support nor agree with the zone mapping for Ontario. The zone developed for Eastern Canada includes the balancing authority jurisdictions for Ontario, Nova Scotia and New Brunswick. Ontario does not have similar weather and climatological patterns to Nova Scotia and New Brunswick. Aggregating these 3 balancing authorities to the same geographical weather zone is not supported by the actual extreme events experienced by each jurisdiction. In fact, Ontario is more likely to share similar weather and climatological patterns with US neighboring balancing authorities NYISO and ISONE than it does with Nova Scotia and New Brunswick.

We strongly suggest that the Province of Ontario be assigned its own weather zone. In addition, at least 2 more weather stations would need to be sampled, similar to what is done for Quebec (refer to table in ERO Benchmark Process). It is not clear which weather station is being currently used for Ontario, but assuming it is from southwestern Ontario (Pearson), weather data from northern (Thunder Bay) and eastern Ontario (Ottawa) would be required for a more accurate representation of Ontario weather patterns.

Likes 1	Ontario Power Generation Inc., 5, Chitescu Constantin
Dislikes 0	
Response	

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	

The zones shown in Attachment 1 lumps Ontario with the Maritimes (New Brunswick, Nova Scotia, and parts of Northern Maine); however, practical experience has shown that there is no reliability benefit to coordinating the extreme weather planning assessments for two reasons:

- Experience has shown that Ontario and the Maritimes are sufficiently distant from each other as to experience extreme temperature conditions at different times. An extreme temperature event in Ontario would not occur at the same time as an extreme temperature event in the Maritimes.
- The balancing areas of Ontario and the Maritimes are not adjacent and the capacity of the transmission system to transfer power between Ontario and the Maritimes is small enough that the power transfered between Ontario and the Maritimes would most likely be negligible during an extreme temperature event.

For the NPCC region, it would make the most sense to divide the weather zones for extreme weather planning assessments along the boundaries of the existing Reliability Coordinator areas, resulting in five different weather zones:

- ISO New York

- ISO New England
- Ontario
- Quebec
- The Maritimes, including New Brunswick, Nova Scotia, and Northern Maine

In addition to the foregoing, New Brunswick Power would like to support the comments of Helen Lainis, Independent Electricity System Operator.

Note that these comments actually apply to R2, which is the requirements for PCs to identify their zone on the map in Attachment 1 -- R1 is actually unrelated to the above question.

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

The zones shown in Attachment 1 lumps Ontario with the Maritimes (New Brunswick, Nova Scotia, and parts of Northern Maine); however, practical experience has shown that there is no reliability benefit to coordinating the extreme weather planning assessments for two reasons:

- Experience has shown that Ontario and the Maritimes are sufficiently distant from each other as to experience extreme temperature conditions at different times. An extreme temperature event in Ontario would not occur at the same time as an extreme temperature event in the Maritimes.
- The balancing areas of Ontario and the Maritimes are not adjacent and the capacity of the transmission system to transfer power between Ontario and the Maritimes is small enough that the power transfered between Ontario and the Maritimes would most likely be negligible during an extreme temperature event.

For the NPCC region, it would make the most sense to divide the weather zones for extreme weather planning assessments along the boundaries of the existing Reliability Coordinator areas, resulting in five different weather zones:

- ISO New York
- ISO New England
- Ontario
- Quebec
- The Maritimes, including New Brunswick, Nova Scotia, and Northern Maine

In addition to the foregoing, New Brunswick Power would like to support the comments of Helen Lainis, Independent Electricity System Operator.

Note that these comments actually apply to R2, which is the requirements for PCs to identify their zone on the map in Attachment 1 -- R1 is actually unrelated to the above question.

Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon does not agree with the zones identified on the map in Attachment 1. We suggest the map should better align to the various temperature gradients a zone may experience. The map that has been proposed seems to prioritize PC and TP boundaries over identifying the geographic regions extreme temperature events have occurred in. Additionally, Exelon supports the comments submitted by the EEI.	
Likes 0	

Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNM Resources (PNMR) is concerned with picking weather data that is comparable between New Mexico and Arizona. We believe differences in weather patterns would impact New Mexico study if building that study to Arizona's summer temperatures.	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Southern Company supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
In general, EEI member companies see some value in retaining the maps included in the TPL-008-1, however, we remain concerned that the temperature regions as proposed in those maps (and elsewhere) are in a number of cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, EEI does not agree that maintaining disconnected parts of SERC and PJM into the broader SERC and PJM temperature zones makes any sense. For this reason, we do not support the temperature zones as currently proposed and ask that they be modified. To address our concerns, we suggest at a minimum that 1) SPP and MISO both be split into a north and south region, and 2) the disconnected portions of SERC and PJM be included into zones that more closely align with their temperature regions.	

EEI is also concerned that benchmark temperature events reside outside of this Reliability Standard placing unnecessary compliance risks for companies. To address this concern, we ask that the benchmark temperature event be included into TPL-008-1 as an attachment.	
Likes 0	
Dislikes 0	
Response	
Michael Brytowski - Great River Energy - 3	
Answer	No
Document Name	
Comment	
The MISO zone should be divided into 2 zones – MISO North and MISO south. The weather differences between Northern Minnesota and Southern Louisiana are too extreme to conduct a meaningful assessment. The winter temperatures in the MISO benchmark event data are just an average January for Minnesota and those winter temperatures will not be experienced in Louisiana. Similarly, the SPP zone should be spilt north and south as well.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
We support Independent Electricity System Operator's and NB Power Corporation comments. Furthermore, Attachment 1 – Extreme Temperature Assessment Zones in accordance with Requirement R2: We agree with Québec being its own Interconnection in the map and in the table, however Québec is the only area that has its own zone in the table which does not correspond to a Weather Zone identified in the Benchmark Process. Similarly, it is not in the list of benchmark temperature event data on the project page under "Benchmark Event Data". For example, ERCOT is identified as its own Interconnection and has its own list of benchmark temperature events. Another example is Florida in the SERC region warrants a separate treatment and has its own benchmark temperature event data. Lastly, the Quebec zone does not appear in the TPL-008 Attachment 1 map, while it is in the table just above. We suggest adding the label "Québec" or "Quebec Interconnection" in white font in the dark blue space represented by the province of Quebec and changing the color of the province of Québec to better reflect that it is its own interconnection.	
Likes 0	

Dislikes 0	
Response	
Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight	
Answer	No
Document Name	
Comment	
The MISO zone should be divided into 2 zones – MISO North and MISO south. The weather differences between Northern Minnesota and Southern Louisiana are too extreme to conduct a meaningful assessment. The winter temperatures in the MISO benchmark event data are just an average January for Minnesota and those winter temperatures will not be experienced in Louisiana. Similarly, the SPP zone should be spilt north and south as well.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS supports the following comments that were submitted by EEI on behalf of its members: In general, EEI member companies see some value in retaining the maps included in the TPL-008-1, however, we remain concerned that the temperature regions as proposed in those maps (and elsewhere) are in a number of cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, EEI does not agree that maintaining disconnected parts of SERC and PJM into the broader SERC and PJM temperature zones makes any sense. For this reason, we do not support the temperature zones as currently proposed and ask that they be modified. To address our concerns, we suggest at a minimum that 1) SPP and MISO both be split into a north and south region, and 2) the disconnected portions of SERC and PJM be included into zones that more closely align with their temperature regions. EEI is also concerned that benchmark temperature events reside outside of this Reliability Standard placing unnecessary compliance risks for companies. To address this concern, we ask that the benchmark temperature event be included into TPL-008-1 as an attachment.	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) supports EEI's partial response to question 1, in regard to benchmark temperature events residing outside the Reliability Standard placing unnecessary compliance risks for companies. CEHE requests that the benchmark temperature events be included into TPL-008-1 as an attachment.	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon does not agree with the zones identified on the map in Attachment 1. We suggest the map should better align to the various temperature gradients a zone may experience. The map that has been proposed seems to prioritize PC and TP boundaries over identifying the geographic regions extreme temperature events have occurred in. Additionally, Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
Comparing the table and map is confusing. There are 20 regions shown in the map and 17 in the table; it is not clear why there is a discrepancy. In addition, the map shows the Quebec colored region as part of Eastern Canada which is different than the table, which separates Quebec and Ontario.	
Likes 0	
Dislikes 0	

Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
R2 (not R1) requires PC to identify their zone in the map included in attachment1. The MISO and SPP zones are spread across multiple temperature regions. This would make it difficult for MISO and SPP to choose a single extreme temperature event that would provide meaningful assessment results across their respective zones. The MISO and SPP zones should be split into MISO North, MISO South, SPP North, and SPP South. Also, the disjointed sections of SERC Central are in a different temperature region that others included in the SERC zone. The disjointed section s of SERC Central should be included in the appropriate MISO or SPP zone that aligns with their temperature region.	
Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1	
Answer	No
Document Name	
Comment	
Zones are nominally adequate, except Eastern Canada which needs to be split into Ontario and the Maritimes. Support SPP's comment - "if the goal is for the PCs to study a 1 in 40-year event for temperature that each PC perform a study for their footprint and share results to the adjacent PCs, similar to the way existing NERC standards are coordinated."	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC sees some value in retaining the maps included in the TPL-008-1, however, we remain very concerned that the temperature regions as proposed in the map (and elsewhere) are in a number of cases far too large to provide meaningful analysis (e.g., MISO and SPP in particular). Additionally, the benchmark temperature events identified for both MISO and SPP do not represent what would be considered extreme temperature events due to their	

large geographically diverse regions. To address our concerns, we suggest at a minimum that SPP and MISO both be split into a north and south region.

ITC is also concerned that benchmark temperature events reside outside of this Reliability Standard placing unnecessary compliance risks for companies. To address this concern, we ask that the benchmark temperature event be included into TPL-008-1 as an attachment.

Likes 0	
Dislikes 0	

Response

Michele Shafer - New York State Electric & Gas (NYSEG) - 6

Answer	No
Document Name	

Comment

Comparing the table and map is confusing. There are 20 regions shown in the map and 17 in the table; it is not clear why there is a discrepancy. In addition, the map shows the Quebec colored region as part of Eastern Canada which is different than the table, which separates Quebec and Ontario.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP does not have any issues with the eastern interconnect portion of the Table and Map. However, SPP does have concerns with the western portion of the Table and Map. The Table and Map seem to group together PCs in a way that could create issues when trying to identify which PCs belong to those zones. There is currently no requirement to post publicly which zone a PC is within, therefore knowing which PC belongs to each zone is not possible.

Consideration is also needed for when a PC footprint changes in the future for this standard since the Table and Map represent current boundaries. If these boundaries change in the future this would require either more coordination or a change to the standard to allow for the boundary to change. A change to the standard would be overly administratively burdensome for such a future change.

There is also a reference in the requirement to Attachment 1 which refers to the Table, however the Map creates confusion when applying the Table due to the use of color code in the east and the lack of color coding in the west for the northwest region. There seems to be a lack of PC boundaries in the western footprint denoted in the Map. SPP would offer that if the Map is needed for Table 1 then the PC boundaries in the west should be identified and color coded appropriately.

Additionally, the technical rationale states the zones have been determined by the Reliability Coordinator (RC) area. SPP believes that breaking the zone by RC footprint is not accurate and should be divided by the PC footprint especially considering that the standard only applies to the PC. PC and RC footprints can be drastically different across the grid.

SPP would like to offer a secondary suggestion that if the goal is for the PCs to study a 1 in 40-year event for temperature that each PC perform a study for their footprint and share results to the adjacent PCs, similar to the way existing NERC standards are coordinated. For instance, there are other standards that utilize language for the applicable entity to study its PC footprint and coordinate with 1st tier entities. SPP believes that language similar to this can accomplish the intended goal without creating a burden if the boundaries change in the Map.

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF

Answer	No
Document Name	

Comment

When considering this requirement with the others for PC's that cover large diverse areas like SPP or MISO, the single temperature consideration for extreme hot or extreme cold does not seem to make sense. For instance, for MISO to use one extreme cold temperature for Texas and for northern Minnesota when they should consider very different extreme temperatures, an extreme cold temperature of 0 in Texas is normal cold for Minnesota. Opposite is true for extreme hot temperatures. PC's should have the ability to select different extreme temperatures within their zone, as worded it does not appear they have that option. This will work if latitude is considered and PC's can use different extreme temperatures within their zone

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
It is not Requirement R1, which requires PCs to identify their zones. Requirement R2 requires PCs to identify their zones and coordinate with other PCs in that zone. Manitoba Hydro has no issues with the identification of the Central Canada zone in Attachment 1.	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD has identified a potential typo in Question 1. Requirement R1 does not stipulate that PCs must identify their zone on the map included in Attachment 1. However, Requirement R2 clearly requires PCs to identify their zone on this map, and SNPD concurs with this requirement.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Although this appears to be an R2.	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
We assume this is in reference to Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Assuming this is referencing R2, not R1: The Zones are appropriate, assuming that the sub-zones in the "Northwest Regions" are treated as separate zones.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	Yes
Document Name	

Comment	
The response to Question 1 is on behalf of MISO since (as the submitter of joint SRC comments) is otherwise unable to submit a Comment Form of its own.	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
PGAE agrees with the zoning, however, overlapping of zones within neighboring entities should be allowed to meet the requirements of extreme weather conditions. Although we agree that the focus of the study is within the boundary, PCs should have the flexibility to consider maybe a little bit past the confines of identified zone as identified in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 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	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 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	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE notes that it is Requirement R2, not Requirement R1 that requires to the PC to identify the zones.

In the Attachment 1 Table, Texas RE recommends revising the Planning Coordinators description to Areas in Texas that are part of the ERCOT Interconnection. This removes the word jurisdiction, since ERCOT does not have jurisdiction over NERC Reliability Standards.

In Requirement R1, Texas RE recommends the following revision for clarity:

R1. Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), **shall identify and document** each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

This clarifies that each Planning Coordinator and Transmission Planner(s) shall document the individual and joint responsibilities for completing the Extreme Temperature Assessment for clarity and to show proof of obligations as the responsible personnel may change from time to time. M1 details that the Planning Coordinator, in conjunction with its Transmission Planner(s), shall provide documentation of each entity's individual and joint responsibilities. However, need for documentation is not included in the Requirement.

Likes 0	
Dislikes 0	

Response

2. The Drafting Team (DT) updated Requirement R2 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirement? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	

LG&E/KU appreciates the effort of the DT to create a process for identifying extreme benchmark temperature events that balances the need for transparency, practicality, and effectiveness. The process described in Requirement R2 provides entities with sufficient clarity on what constitutes an extreme benchmark temperature event, while also affording entities flexibility in how and which events are selected.

LG&E/KU would request the DT consider whether Requirement R2 and its VSLs could be modified to address the situation where one (or more) Planning Coordinators in a zone does not coordinate. As-is, the Requirement R2 language could be understood as all other PCs in that zone also being out of compliance.

Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	

The role of ERO seems to be reduced to footnote 1, the DT further needs to clarify what “maintain” means in this context. PGAE would like to better understand the benefits of using benchmark libraries over local extreme weather conditions. We would like to see the periodicity of this maintain obligation for the ERO. If the DT could expand on the footnote 1 to provide clarification of ERO maintaining the library and how often ERO would be updating the library of benchmark temperature events.

Likes 0	
Dislikes 0	
Response	

Michael Goggin - Grid Strategies LLC - 5

Answer	No
Document Name	
Comment	

the new requirement proposed in R2 2.1 in the updated draft that the event selected represent “one of the 20 most extreme temperature conditions” may result in entities selecting events that are not representative of the most severe generation shortfalls they are likely to experience. First, entities should be required to select from a smaller number of most severe events, like the three most severe events. Second, the ranking of events should not be based on most extreme temperature, but rather most severe generation shortage, accounting for both higher demand and higher generator outage rates during the event. This will accurately reflect that temperature alone does not determine the severity of an event, as wind speed, insolation, and other factors affect how extreme cold and heat affect both generator outages and the need for building heating or cooling.

Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4

Answer	No
Document Name	
Comment	

USV has concerns about the proposed language in R2, Part 2.1. 40 years of temperature data is an immense amount of data. The data collected 40 years ago compared to today’s temperatures may not be accurate and could construed the data from the last 20-25 years. We believe that there have been enough recent extreme weather events in the last 25 years to accurately consider extreme heat and extreme cold benchmark temperatures. We recommend that the drafting team consider utilizing a timeline closer to 20 years and not 40 years.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	

The Table and Map seem to group together PCs in a way that could create issues when trying to identify which PCs belong to those zones. There is currently no requirement to post which zone the PC is in, therefore knowing which PC belongs to each zone is not possible, specifically for the western portion of the Table and Map.

Likes 0	

Dislikes 0	

Response

Michele Shafer - New York State Electric & Gas (NYSEG) - 6

Answer	No
Document Name	

Comment

The intent of the standard is to perform an extreme temperature assessment, but R2 allows for selection from the “20 most extreme” events from a period of 40 years. This could result in an entity being able to select an event that is relatively mild but still maintain compliance. This could be mitigated by narrowing the number of extreme events to select from down to a lower number, for example 10.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

See comments for question1. Additionally, the SDT should consider an official library or other repository from which the common extreme heat benchmark temperature event and common extreme cold benchmark temperature event is chosen. This library should either be included as an attachment to this standard, or the official location and maintenance should be documented within this standard.

If no official library is document, this could lead to ambiguities and inconsistencies in performing the assessment and in auditing this requirement.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
The intent of the standard is to perform an extreme temperature assessment, but R2 allows for selection from the "20 most extreme" events from a period of 40 years. This could result in an entity being able to select an event that is relatively mild but still maintain compliance. This could be mitigated by narrowing the number of extreme events to select from down to a lower number, for example 10.	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
In the current zone designations, there are some zones where temperature differences would be significant due to their very large north/south geographical spans. A concern arises whether the chosen extreme temperature event case is applicable to the overall zone in these cases. It might not be representative of certain parts of the zone. Each Planning Coordinator, in conjunction with its Transmission Planner(s) shall select which extreme heat and extreme cold weather events to develop benchmark extreme temperature events applicable to their region.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	No
Document Name	
Comment	

The **ISO/RTO Council (IRC) Standards Review Committee (SRC)[1]** supports the intent of Requirement R2, i.e., to provide Planning Coordinators (PCs) with the option of selecting a benchmark temperature event from the ERO library or the ability to develop one or more benchmark temperature events on their own. If the PC(s) select an event from either the ERO library, the ERO is responsible for providing data in support of Parts 2.1 and 2.2. Alternatively, if the PC(s) elects to develop a benchmark temperature event, the PC(s) is responsible for providing data in support of Parts 2.1 and 2.2. Therefore, the SRC proposes the following modification to clarify the intent of Requirement R2:

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event ***from either the benchmark library developed, approved and maintained by the Electric Reliability Organization (ERO) or elect to develop one or both common benchmark temperature event(s)*** for each of its identified zone(s) when completing the Extreme Temperature Assessment.1 ***Each*** benchmark temperature event shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

The SRC recommends that Part 2.2 be revised as follows to clarify the link between Part 2.2 and Part 2.1: “Represent one of the 20 most extreme temperature conditions **within the period identified in Part 2.1** based on the three-day rolling average…”

The SRC recommends that footnote 1 be revised to clarify that the ERO library may not contain all valid benchmark temperature events as Planning Coordinators are free to develop their own benchmark temperature events: “The Electric Reliability Organization (ERO) will maintain a library of the benchmark temperature events developed by the ERO that meet the criteria of Requirement R2, inclusive of Parts 2.1 and 2.2.”

The SRC also requests that the drafting team clarify how the event temperature information (available on NERC’s website) is intended to be used, and more specifically, whether it is to be applied across the entire zone.

[1] For purposes of these comments, the IRC SRC includes the following entities: IESO, ISO-NE, MISO, NYISO (except for a portion of our response to question 3 as noted in our response to question 3), PJM and SPP.

Likes 0	
Dislikes 0	

Response

Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight

Answer	No
Document Name	

Comment

Requirement R2 and R3 following R1 creates confusion when reading the responsibilities of requirements 4-11. Consider reordering – R2, R3 then R1. Coordinating Zones, develop benchmark planning then conducting the assessments. The Transmission Planner (TP) is not referenced in R2 or R3.

R2 currently – Coordinating Zones

Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment.

R3 currently – a process for developing benchmark planning

Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases.

R1 currently – The assessments

Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	No
Document Name	

Comment

Ameren believes the language in sections 2.1 and 2.2 are too prescriptive. We believe the Planning Coordinator should work with stakeholders to determine the data set that will be used to derive extreme heat and cold weather temperatures. Does the planning coordinator have the ability to carve the zones?

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

We support Independent Electricity System Operator’s and NB Power Corporation comments.

Furthermore, our understanding of the Benchmark Process is that the Weather Zones were used to develop the lists (library) of Benchmark Events, and therefore each Weather Zone has its library. Our interpretation of the current document would be that Québec shares the same library "Eastern Canada" as our Canadian neighbors, without however having to choose the same events every 5 years because we are alone in our ETA Zone as per the table in Attachment 1.

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Great River Energy - 3

Answer	No
Document Name	

Comment

Requirement R2 and R3 following R1 creates confusion when reading the responsibilities of requirements 4-11. Consider reordering – R2, R3 then R1. Coordinating Zones, develop benchmark planning then conducting the assessments. The Transmission Planner (TP) is not referenced in R2 or R3.

R2 currently – Coordinating Zones

Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment.

R3 currently – a process for developing benchmark planning

Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases.

R1 currently – The assessments

Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity’s individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power is concerned that there may be circumstances where not all Planning Coordinators in a zone will agree to one common cold and heat event. Instead of using "all Planning Coordinators" in the R2 Requirement language, Tacoma Power recommends using "majority of Planning Coordinators", as shown in the mark-up below. Tacoma Power also recommends the following changes to the R2 language. This change makes it clear that there's two distinct steps to this Requirement: 1) identifying the zone(s) and then 2) selecting two common events for all PCs in that zone. "Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1. **The majority of Planning Coordinators within each of its identified zone(s) shall select** one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment."	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
Please see comments for Question 1.	

Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
Please see comments for Question 1	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
In the current zone designations, there are some zones where temperature differences would be significant due to their very large north/south geographical spans. A concern arises whether the chosen extreme temperature event case is applicable to the overall zone in these cases. It might not be representative of certain parts of the zone.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

It is inadequate for TPL-008 and for all NERC cold weather-related standards to select. just one cold weather benchmark, based exclusively on temperature. Several scenarios must be studied, covering the vulnerabilities of the various generation plant types – extreme cold plus high wind for conventional facilities, ice storms and wind droughts for wind turbines, nighttime and snow coverage for solar farms.

The best benchmarks are “perfect storm” combination events. What made Winter Storm Uri so destructive, for example, was that it began with an ice storm that took-out the wind fleet of northern Texas, followed by a deep freeze with high winds that tripped many conventional plants, then a wind drought that prevented the now-deiced wind turbines from helping.

The lookback period should be 50 years, to coincide with the 50-year periodicity data published by ASHRAE. NERC should in general make more use of ASHRAE data, to avoid making entities develop databases that are already available as a look-up.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	

Comment

The Attachment 1 graphic would greatly benefit from including state boundaries, as well as mentioning the NERC benchmark library. Additionally, clarification added that entities may select events that meet these criteria, either from the library or as identified by the group of Coordinators. Please emphasize this flexibility of choice - it is likely to be lost in time.

NERC's consultant uses BA load weighting (based on notes and conversations provided in the 9/10 TPL-008 presentation). As a result, this weighting practice does not appear to directly meet this proposed R2.2 language regarding the most extreme events for a region. The temperature may not actually be representative of “across the zone” because of this weighting. Of reliability considerations, load is certainly part of the need, but potential impacts to generation and the connecting transmission, which may be in other regions, are also important pieces to the delivery of resource to load. Removal or modification of this R2 ‘most extreme’ language is recommended; or exempting the NERC library from needing to follow these criteria. Alternately, the SDT may modify to allow weighting to be used in method.

Because the NERC Extreme Weather Event library is only updated every 3 years in the current plan, it is possible that an event in the library would contain events that would not meet these R2 criteria for event “freshness”. The SDT may wish to consider modifying the language regarding time, or an additional clause, to permit events currently in the NERC Extreme Weather Event library to not be subject to the selection criteria currently in R2, or that entities may use the other criteria to evaluate and select other events.

Likes 0	
Dislikes 0	

Response

Michele Tondalo - United Illuminating Co. - 1

Answer	No

Document Name	
Comment	

The intent of the standard is to perform an extreme temperature assessment, but R2 allows for selection from the “20 most extreme” events from a period of 40 years. This could result in an entity being able to select an event that is relatively mild but still maintain compliance. This could be mitigated by narrowing the number of extreme events to select from down to a lower number, for example 10.

Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	Yes
Document Name	
Comment	

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	

ERCOT agrees with the updates to Requirement R2, and proposes the following clarifications based on ERCOT’s understanding of the intent and function of Requirement R2.

- To better reflect the role that the Planning Coordinator’s selection plays in Parts 2.1 and 2.2, ERCOT recommends that the last sentence of the first paragraph of Requirement R2 be revised to read “The Planning Coordinator’s selection of benchmark temperature events shall:”

- ERCOT recommends that Part 2.2 be revised as follows to clarify the link between Part 2.2 and Part 2.1: “Represent one of the 20 most extreme temperature conditions **within the period identified in Part 2.1** based on the three-day rolling average…”

- ERCOT recommends that footnote 1 either be removed or revised as follows to clarify that the ERO library might not contain all valid benchmark temperature events, as Planning Coordinators are free to select benchmark temperature events that meet the criteria of Requirement R2 even if those events are not in the ERO library: “The Electric Reliability Organization (ERO) will maintain a library of **some, but not necessarily all, of the** benchmark temperature events that meet the criteria of Requirement R2.”

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC supports the proposed changes made to Requirement R2.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	Yes
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

WECC voted Affirmative for TPL-008 due to the timelines imposed on NERC by FERC. However, WECC still has some comments for the DT to consider. WECC is concerned that the proposed language for R2 may be unclear. WECC understands that the intent of R2 is to allow PCs the option of selecting a benchmark temperature event f rom the ERO library OR the ability to develop one or more benchmark temperature events based on their own experiences. If a PC selects an event fromt he ERO library, the EOR would be responsible for providing supporting data. However, if the PC elects to develop a benchmark temmperature event, the PC would be responsible for providing supproing data. If our understanding is corret, WECC suggests the following modifications for clarity in R2:

Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event **from the benchmark library approved and maintained by the Electric Reliability Organization (ERO) or elect to develop one or both common benchmark temperature event(s)** for each of its identified zone(s) when completing the Extreme Temperature Assessment.1 Selected Each benchmark temperature events shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Additionally, it is WECC's understanding that a Minimum of one of each type of benchmark temperature event is required to be seleted. As written, the requirement seems to indicate that only one may be seleted. It a minimum of one of each type is necessary, WECC suggests that the words "at least" be added back to the requirement. If accepted this would need to be reflected in the Measure and VSLs as well.

Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirement R2.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed changes made to Requirement R2.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR supports R2.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes

Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	

Comment	
SNPD supports the zones outlined in the map provided in Attachment 1. However, the graphic would be significantly improved by incorporating state boundaries and referencing the NERC benchmark library.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro supports the intent of R2, where PC identifies common extreme heat and extreme cold weather events applicable to its zone. However, Manitoba Hydro recommends that PCs be given the option to select such events from the ERO-maintained benchmark event list or use their own experience to develop benchmark extreme temperature events applicable to their region.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF supports the intent of Requirement R2; however, believes the proposed language as currently written is unclear. Our understanding is the intent of R2 is to provide Planning Coordinators (PCs) with the option of selecting a benchmark temperature event from the ERO library or the ability to develop one or both benchmark temperature events on their own. If the PC(s) select an event from the ERO library, the ERO is responsible for providing data in support of Parts 2.1 and 2.2. Alternatively, if the PC(s) elects to develop a benchmark temperature event, the PC(s) is responsible for providing data in support of Parts 2.1 and 2.2. Therefore, the MRO NSRF proposes the following modification to clarify the intent of Requirement R2: R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event **from the benchmark library approved and maintained by the Electric Reliability Organization (ERO) or elect to develop one or both common benchmark temperature event(s)** for each of its identified zone(s) when completing the Extreme Temperature Assessment. **Each** benchmark temperature events shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]	

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy has no comments toward R2.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

The proposed R2 language as currently written is unclear. Our understanding is the intent of R2 is to provide Planning Coordinators (PCs) with the option of selecting a benchmark temperature event from the ERO library or the ability to develop one or both benchmark temperature events on their own. If the PC(s) select an event from the ERO library, the ERO is responsible for providing data in support of Parts 2.1 and 2.2. Alternatively, if the PC(s) elects to develop a benchmark temperature event, the PC(s) is responsible for providing data in support of Parts 2.1 and 2.2. Therefore, we proposes the following modification to clarify the intent of Requirement R2:

R2. Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event from the benchmark library approved and maintained by the Electric Reliability Organization (ERO) or elect to develop one or both common benchmark temperature event(s) for each of its identified zone(s) when completing the Extreme Temperature Assessment. Each benchmark temperature event shall: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes

Document Name	
Comment	
AEP agrees with the changes made to R2, but requests that content be added to make it clear that usage of the ERO-maintained library of benchmark temperature events is optional.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF	
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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
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	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	
Document Name	
Comment	
We agree with the plan, although there should be some method to help ensure coordination on scenario selection and case data submittal among all PCs in a zone. How will disagreements among PC's be resolved? Voting? Regions can probably resolve this on their own most of the time, but there may be disputes that need to be resolved somehow.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the Technical Rationale states that "Requirement R2 does not preclude entities from collecting collect temperature data and identifying benchmark temperature events through their own processes". Texas RE recommends Footnote 1 acknowledge this and recommends the following revision (in bold):	

"The Electric Reliability Organization (ERO) will maintain a library of benchmark temperature events that meet the criteria of Requirement R2. **Planning Coordinator(s) may identify their own benchmark temperature events provided the selected benchmark meet R2 criteria and the Planning Coordinator provides evidence of technical justification**."

Since the periodicity of extreme heat and cold events are increasing in the recent years and the trend may continue to show strongest increase in extremes. The selected benchmark temperature event shall include all the extreme events closest to the benchmark selection process. Consider changing the requirement in 2.1 to include 'temperature data ending no more than two years prior to the time the benchmark temperature events are selected". Texas RE recommends the following revision (in bold):

2.1. Consider no less than a 40-year period of temperature data ending no more than **two** years prior to the time the benchmark temperature events are selected; and

Likes 0	
Dislikes 0	

Response

3. The DT updated Requirements R3 – R4 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with the modifications in Requirements R3 and R4. These changes adequately balance the need for transparency, practicality, and effectiveness. LG&E/KU would request the DT consider whether Requirement R3 and its VSLs could be modified to address the situation where one (or more) Planning Coordinators in a zone does not coordinate. As-is, the Requirement R3 language could be understood as all other PCs in that zone also being out of compliance.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Requirement R3: The prior draft of TPL-008 contained language in R3 that required “Planning Coordinator(s), Transmission Planner(s), and other designated study entities” to collectively implement the requirement. We request language along these lines be reinstated such that all parties that play a role in implementing the process for developing benchmark planning cases must comply. Our suggested language modification below: **R3.** Each Planning Coordinator shall coordinate with all Planning Coordinators and each responsible entity (identified in Requirement R1) within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases… Note: If adopted, the Technical Rationale for R3 will also need to be updated to reflect this change.	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	
Comment	

In FERC Order 896, paragraph 39, there is a Commission Determination as follows:

"*We also direct NERC to include in the Reliability Standard the framework and criteria that responsible entities shall use to develop from the relevant benchmark event planning cases to represent potential weather-related contingencies (e.g., concurrent/correlated generation and transmission outages, derates) and expected future conditions of the system such as changes in load, transfers, and generation resource mix, and impacts on generators sensitive to extreme heat or cold, due to the weather conditions indicated in the benchmark events. Developing such a framework would provide a common design basis for responsible entities to follow when creating benchmark planning cases. This would not only help establish a clear set of expectations for responsible entities to follow when developing benchmark planning events, but also facilitate auditing and enforcement of the Standard*."

In review of Order 896, we find the term "contingencies" is used two different ways. Paragraph 39 describes things that are in the base or N-0 state – for example, a cold weather event occurs, and certain wind generators can no longer operate – this as a base contingency. Similarly, in paragraph 88, there is an additional Commission Determination as follows, in further support of these baseline "contingency" outages:

"*Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events as described in more detail below*."

Then later, in Paragraph 92 (still under the Commission Determination), FERC further clarifies:

"*Regarding the comments of NYISO and EPRI on the difference between extreme events and contingencies covered under Reliability Standard TPL-001-5.1, we clarify that all contingencies included in benchmark planning cases under the new or modified Reliability Standard will represent initial conditions for extreme weather event planning and analysis. These contingencies (i.e., correlated/concurrent, temperature sensitive outages, and derates) shall be identified based on similar contingencies that occurred in recent extreme weather events or expected to occur in future forecasted events*."

From these, it is clear that Order 896 is expecting "contingencies" of weather-based equipment outages to be part of the base or N-0 system state. The more traditional "contingencies" are then addressed on top of this condition, as presented in Order 896, Section G, starting at Paragraph 95.

The specific request from this comment is for the SDT to clarify how it expects such base "contingencies" to be included in the model. There does not appear to be language currently in the standard in support of this, and it is clear from Order 896 that it is expected both the base model outage "contingencies" and then subsequent contingency events to test system performance.

Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	
Comment	

Once again, focusing exclusively on dry bulb temperature is inadequate for TPL-008 and for all NERC winter weather-related standards. Ref. R3.2 for example, there are no simple and reliable, "[dry bulb] temperature dependent adjustments for Load." A wind chill basis is needed. Mistakenly assuming that load tracks the DBT is why some ISOs severely under-predicted the peak load for Winter Storm Elliott, which was only moderately cold but had extremely strong winds.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Requirement R3: The prior draft of TPL-008 contained language in R3 that required "Planning Coordinator(s), Transmission Planner(s), and other designated study entities" to collectively implement the requirement. The MRO NSRF requests language along these lines be reinstated such that all parties that play a role in implementing the process for developing benchmark planning cases must comply. Our suggested language modification below: R3. Each Planning Coordinator shall coordinate with all Planning Coordinators **and each responsible entity (identified in Requirement R1)** within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases… Note: If adopted, the Technical Rationale for R3 will also need to be updated to reflect this change.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	

Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Tacoma Power is concerned that there may be circumstances where not all Planning Coordinators in a zone will agree to one common cold and heat event. Instead of using "all Planning Coordinators" in the R3 Requirement language, Tacoma Power recommends using "majority of Planning Coordinators", as shown in the mark-up below.

"Each Planning Coordinator shall coordinate with **the majority of the** Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases."

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	

Comment

Eversource recommends reinserting from Draft 2 the Transmission Planner as part of the coordination in R3:

Each Planning Coordinator shall coordinate with all Planning Coordinators **and Transmission Planners** within each of its zone(s)…

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	No

Document Name	
Comment	
Ameren would like more clarification around R3 sections 3.2 and 3.3. Will MOD-032 be revised to include extreme temperature data?	
Likes 0	
Dislikes 0	
Response	
Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight	
Answer	No
Document Name	
Comment	
GRE supports the comments of the NSRF and GRE has additional comments	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	No
Document Name	
Comment	

Requirement R3: The prior draft of TPL-008 contained language in R3 that required "Planning Coordinator(s), Transmission Planner(s), and other designated study entities" to collectively implement the requirement. The SRC requests language along these lines be reinstated such that all parties that play a role in implementing the process for developing benchmark planning cases must comply. Our suggested language modification below:

R3. Each Planning Coordinator shall coordinate with all Planning Coordinators ***and each responsible entity (identified in Requirement R1)*** within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases…

Note: If adopted, the Technical Rationale for R3 will also need to be updated to reflect this change.

In addition, the SRC[1] is concerned that Requirement R3 unnecessarily and inadvertently limits the ability of entities to properly develop their benchmark planning cases. Specifically, the SRC is concerned that R3 could be understood to mean that entities are limited to making the adjustments specifically described in R3 and are prevented from making adjustments necessary to update the planning cases to reflect the expected future state of the system or to ensure that the generation necessary to serve load is available so that the case can solve. As the drafting team recognizes in the Technical Rationale, adjusting the case to ensure that it contains enough generation to serve the modeled load is essential to ensure that the standard does not stray into the realm of resource adequacy issues and fully complies with paragraph 94 of FERC Order No. 896, which states that resource adequacy is not in scope for this project.

To address this, the SRC recommends that the drafting team renumber the current Part 3.4 to Part 3.5 and add a new Part 3.4 that reads as follows:

"3.4. Adjustments to the total modeled generation or Load in each case as necessary to allow the total modeled generation to serve the total modeled System Load."

The SRC also recommends that Requirement R4 be revised as needed to align with any revisions made to Requirement R3.

Requirement R4: FERC Order 896 paragraph 154 is clear that FERC does not intend to order the construction of new transmission facilities through this standard. However, due to the inherently extreme nature of these contingency scenarios, Corrective Action Plans will likely have to include facility upgrades that would not have been needed under current system design criteria under TPL-001-5.1. Since TPL-001-5.1 studies are conducted annually, and ISO/RTOs have processes outside NERC standards to identify transmission expansion projects that may be identified before the next 5-year TPL-008 study period, we recommend TPL-008 be revised to allow the CAPs to be updated as determined by the PC, thereby accommodating regional planning solutions to mitigate deficiencies identified under TPL-008 without having to wait 5 years for the next TPL-008 study cycle or conduct a completely new series of TPL-008 studies to update the CAP.

Requirement R3.4: We recommend the SDT consider updating R3.4 or the Technical Rationale to include broader system conditions for sensitivity studies, as the conditions for the sensitivity cases seem to be focused on steady state analysis when there could be other assumptions to consider that affect system dynamic performance, for example, dynamic load models, DER dynamics, etc.

[1] NYISO abstains from this comment and the associated proposed revision to Part 3.4.

Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) does not agree sensitivity case requirements are needed as these place an unnecessary burden on Entities with little reliability benefit. CEHE recommends the removal of Requirement R4.2 in order to agree with Requirements R3 and R4 as written. FERC Order 896 is expecting "contingencies" of weather-based equipment outages to be part of the base or N-0 system state. The more traditional "contingencies" are then addressed on top of this condition, as presented in Order 896, Section G, starting at Paragraph 95. CEHE recommends for the SDT to clarify how it expects such base "contingencies" to be included in the model. There does not appear to be language currently in the standard in support of this, and it is clear from Order 896 that it is expected both the base model outage "contingencies" and then subsequent contingency events test system performance.	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
See comment to question 2, If "at least" one of each type of benchmark temperature event is required, Parts 4.1 and 4.2 would need to be modified to reflect this.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
There are no issues with R3. The SDT should consider removing R4.2, since the assessment already covers multiple extreme weather scenarios. There is questionable reliability benefit in running additional sensitivities that do not rise to the level of requiring (or eliminating) corrective actions.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF	
Answer	No
Document Name	
Comment	
10 year cases may not be the most appropriate for identification of binding improvements as estimates of generation additions and retirements and load additions are still developing. Five year cases should provide sufficient detail to identify needed reliability improvements while still allowing time for construction.	
Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT is concerned that Requirement R3 unnecessarily and inadvertently limits the ability of entities to properly develop their benchmark planning cases. Specifically, ERCOT is concerned that R3 could be understood to mean that entities are limited to making the adjustments specifically described in R3 and are prevented from making adjustments necessary to ensure that the generation necessary to serve load is available so that the case can solve. As the drafting team recognizes in the Technical Rationale, adjusting the case to ensure that it contains enough generation to serve the modeled load is essential to ensure that the standard does not stray into the realm of resource adequacy issues and fully complies with paragraph 94 of FERC Order No. 896, which states that resource adequacy is not in scope for this project.

To address this, ERCOT recommends that the drafting team revise Part 3.2 by replacing the period at the end of Part 3.2 with the following: ", provided that the responsible entity may adjust the total modeled generation or Load in each case as necessary to allow the total modeled generation to serve the total modeled System Load."

ERCOT also recommends that Requirement R4 be revised as needed to align with any revisions made to Requirement R3.

Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

First, to comply with FERC Order 896, the standard should specify that benchmark events and Extreme Temperature Assessments will account for concurrent/correlated outages of generators during extreme heat and cold events. In Order 896 paragraph 88, FERC directs "NERC to require under the new or revised Reliability Standard the study of concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark events," explaining in paragraph 89 that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events."

The draft of TPL-008 R3 appears to put the burden on responsible entities and not NERC for accounting for correlated outages in making "seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers" and conducting sensitivity analyses.

Having responsible entities and not NERC conduct this adjustment increases the risk that different regions will use inconsistent methods for doing so, and at worst responsible entities that want to avoid addressing reliability concerns through a Corrective Action Plan will use unrealistically low assumptions for the rate of correlated generator outages or other input assumptions like load and transfers. This assumption can have such a large impact on results it cannot be left to responsible entities, and should be made by NERC. The drafting team's Technical Rationale used similar logic in deciding that NERC (the Electric Reliability Organization or ERO) should assemble the benchmark planning cases: "to ensure consistency across regions, it is necessary for the ERO to have the responsibility for determining the suitability of benchmark events to represent probable future conditions."

Given the significant variation in the rates at which different fuel types experience correlated outages,[1] and rapid changes in the generation mix that may cause the future power system to have greater or lesser exposure to correlated outage risk, it is particularly important for the benchmark events and Extreme Temperature Assessments to account for the concurrent/correlated outage risk of each fuel type in the future generation mix. In recent cold snap events, gas generator outages due to equipment failures and fuel supply interruptions have accounted for the majority of outages. NERC GADS data can be used to assess the rate of correlated outages and derates of generators by fuel type.{C}[2]

Second, the benchmark cases and Extreme Temperature Assessments should account for changes to generation, demand, and transmission resulting from climate change, electrification of heating, and other factors that are affecting the risk posed by extreme heat and cold. Accounting for how climate change is increasing the frequency and magnitude of extreme heat and cold events is consistent with FERC's Order 896 directive in paragraph 40: "We also direct NERC to ensure the reliability standard contains appropriate mechanisms for ensuring the benchmark event reflects up-to-date meteorological data. The increasing intensity, frequency, and unpredictability of extreme weather conditions requires that key aspects of the benchmark events be reviewed, and if necessary, updated periodically to ensure the corresponding benchmark planning cases reflect updated meteorological data." Electrification of heating is also increasing the sensitivity of electricity demand to extreme cold conditions, which should be accounted for in the benchmark cases and Extreme Temperature Assessments.

Third, due to the impact of climate change, electrification, and rapid changes in the generation mix, requirement R1 should require responsible entities to complete an Extreme Temperature Assessment more frequently than at least once every five calendar years. As noted above, FERC Order 896 specifies that the meteorology underlying benchmark cases should be updated at least every five years, but the generation mix and other grid conditions can change more rapidly than that. TPL-001 requirement R2 requires Planning Assessments to be conducted annually, and a similar annual requirement for Extreme Temperature Assessments is appropriate given that extreme heat and cold events are the largest threat to electric reliability.

{C}[1]{C} *See, e.g.*, FERC and NERC*, Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (October 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022, at 17; FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16; FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf; PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

{C}[2]{C} For example, see the analysis of GADS data provided in S. Murphy et al., *Resource adequacy risks to the bulk power system in North America* (February 2018), https://www.sciencedirect.com/science/article/pii/S0306261917318202, with Supplementary Material including outage data available at https://ars.els-cdn.com/content/image/1-s2.0-S0306261917318202-mmc1.zip

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment
In R4, Extreme Temperature Events is already a “sensitivity” to the normal long-term planning cases. The cases will be built with Gen/Load/Transmission/Transfer based on the extreme weather conditions. The need for sensitivity cases on top of “sensitivity cases” is not very convincing. Furthermore, the DT should explain if the sensitivity would be the same factor that one would modify or if you could change the sensitivity factor that you modify. For example, let's say we have decided to adjust loads so that they're higher in the extreme heat sensitivity, but we wanted to pick transfer levels with extreme cold. In R3.4 it is not specified if a different adjustment factor can be used for each one of the extreme cold/extreme heat sensitivity cases or there is flexibility. We request DT to add clarity to prevent misinterpretation, or for an auditor to step in and assign a restriction that's not there. We would prefer to see R3.4 modified to say a different sensitivity, a different change can be made to the two different temperature cases or something that specifies you don't have to use the same one.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment
R3 and R4 appear duplicative in that they both involve the formation of study cases. R3 states “Implement a process for developing benchmark planning cases” while R4 states “Use the coordination process… to develop the following… planning benchmark cases.”

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment
FirstEnergy has no comments toward these requirement drafts.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

To improve the clarity of R3.4, it is recommended to consider updating R3.4, as shown below:

3.4. Identification of changes to at least one of the following conditions for sensitivity cases:

· Generation additions, retirements. (it is not clear what is expected by just listing generation)

· Real and reactive forecasted Load.

· Expected transfers.

· Expected in service dates of new or modified Transmission Facilities. (a new addition that Manitoba Hydro recommends to be included in the sensitivity list)

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR supports R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
EEI supports the proposed changes made to Requirements R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

See EEI Comments

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC supports the proposed changes made to Requirements R3 and R4.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
We understand and approve the proposed language in R3-R4. However, we recommend that the drafting team includes more clarity and benchmarks for the process for sensitivity cases. The technical rationale currently does not include details as to how to develop or implement sensitivity cases.	

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
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	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 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	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends defining "the zone" in Requirement Part R3.3. Texas RE recommends the following revision (in bold):	

R3.3. Assumed seasonal and temperature dependent adjustments for Load,

generation, Transmission, and transfers in areas outside the zone **identified in Requirement R2**, as needed.

Texas RE noticed that neither R3 nor R4 mention a requirement to include "concurrent" generator and transmission outages as noted in FERC Order No. 896, which states: "…the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied". The Considerations of the Order document says "Per Requirement R4, the data necessary to build the benchmark planning cases must be provided via MOD-032 and supplemented by other sources as needed. Any concurrent/correlated generator and transmission outages due to extreme heat and cold events in benchmark temperature events should be reflected in the model data and thus represented in the initial conditions of the benchmark planning cases."

Based on the current Requirements R3 and R4 language, the cases could be built with high loads and high generation dispatch for the extreme weather without including concurrent outages. Therefore, a requirement in R3 or R4 that specifically says to include "concurrent" generator and transmission outages in the initial conditions of the benchmark planning cases needs to be added in accordance with the FERC Order. Also, the rationale for those concurrent outages selected for the initial conditions shall be available as supporting information. Texas RE noticed that the Technical Rationale does mention concurrent outages and recommends incorporating this language directly into the requirement language itself through the note described below.

Requirement R4.2 also does not specify which system conditions should be varied to create sensitivity cases. Normally sensitivity studies are conducted to identify system deficiencies under stressed system conditions such as generation changes, load variations, delays in implementing system improvements, multiple system elements being unavailable due to extended outages, etc.

Texas RE recommends the following revisions to Requirement R4 and Requirement 4.2 to clarify the language, address concurrent outages, and clarify the requirements for sensitivity cases:

R4. Each responsible entity, as identified in Requirement R1, shall use the coordination process developed in accordance with Requirement R3 and data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, **to develop the following and** establish category P0 as the normal System condition in Table 1 **and develop and maintain the following**:

4.2 One common extreme heat and one common extreme cold sensitivity case **by varying one or more of the system conditions such as forecasted load, generation dispatch, unavailability of multiple system elements (overlapping outages), etc. to stress the system sufficiently to demonstrate measurable changes in system responses**.

Texas RE further recommends adding the following as a note under Requirement 4:

Planning Coordinator shall use coincident peak load for extreme temperature assessments to more appropriately reflect load conditions during system-wide weather conditions. Transmission Planner(s) shall use the forecasted non-coincident peak load for evaluating its respective area assessments.

Likes 0	
Dislikes 0	

Response

4. The DT updated Requirements R7 – R8 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with the modifications in Requirements R7 and R8 (as well as those in Requirements R5 and R6 which do not have a dedicated question on this comment form). These modifications improve the clarity of the standard.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	
Please see PG&E's comments in (Q3) for R4 as R8 is in reference to R4.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	
SPP has identified an inconsistency between the proposed requirement language and the technical rationale. The technical rationale denotes the expectation to run at a minimum P0, P1, P7 whereas the language in the requirement states "Contingencies for each category in Table 1 that are	

expected to produce more severe System impacts". This indicates a compliance obligation to produce a contingency list for the entire table instead of only those in the P0, P1, P7 categories as stated in the technical rationale.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
Regarding R8, it is unclear if the responsible entity must identify continencies for each event type shown within each category, or only those event types that are expected to produce more severe System impacts on its portion of the Bulk Electric System	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not agree with sensitivity cases in Extreme Temperature Assessments for the same reasons as mentioned in Q3. CEHE recommends the removal of 8.2 in order to agree with Requirements R7 and R8.	
Likes 0	
Dislikes 0	
Response	
Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight	
Answer	No
Document Name	
Comment	

GRE supports the comments of the NSRF and GRE has additional comments

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

The steady state contingencies do not necessarily apply for transient stability. The transient stability contingencies are a subset of the steady-state contingencies.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	Yes
Document Name	

Comment

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC is supportive of the proposed changes made to Requirements R7 and R8.

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R7 and R8.	
Likes 0	

Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI is supportive of the proposed changes made to Requirements R7 and R8.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR supports R7 and R8.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R7 and R8.	
Likes 0	
Dislikes 0	
Response	

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Requirement # 7 states: *"Each responsible entity, as identified in Requirement R1, shall identify the Contingencies for each category in Table 1 that are expected to produce more severe System impacts on its portion of the Bulk Electric System. The rationale for those Contingencies selected for evaluation shall be available as supporting information."* Questions to the SDT for clarification: Is the intent is that the entity **must** identify contingencies for each contingency Event (such as P1.1, P1.2, P7.2 for example) – or must have a rationale why certain events (such as P7.2 for example) are not the more severe? Without clarification, this requirement could be interpreted differently by auditors. Additionally, we interpret that the BES Contingency voltage level of >= 200 kV is meant to be a filter or screening criteria for identifying events that must be considered and that would have a more severe impact on the BES. We also interpret that as part of the Extreme Temperature Assessment, an entity is responsible for monitoring their entire BES. Is this interpretation correct? Some elaboration on the 200 kV threshold within the Technical Rationale would be helpful.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	

Comment	
R8: For Table 1 – Steady State & Stability Performance Events, #6, please explain the rationale for stating the requirements for CAP's in Footnote 6 rather than in Requirement 9. R9: Organization of Footnote 6 is confusing because it is written with Requirement-like language that should reside in R9 itself.	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments toward these requirement drafts.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Please see AEP's response to Question #7 which includes references to R8.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF	
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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
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

Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton

Answer	
Document Name	

Comment

Abstain

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE is concerned that multiple contingencies may not be used to assess the system in extreme temperature events. In Requirement R7, Table 1 only shows single contingencies and double circuit contingencies for assessing steady state and stability performances. Based on the contingencies listed in Table 1, the reasoning for R7 is not clear. Are the responsible entities expected to select single contingencies and double circuit contingencies and use those contingencies to assess the system?   During extreme temperature events, multiple overlapping contingencies generally happens, and they are expected. Registered entities should study the overlapping contingencies to identify system deficiencies and prepare the mitigation plans.

Additionally, the NERC Glossary Definition of Firm Transmission Service states: The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. Texas RE inquires as to why interruption of Firm Transmission Service is allowed under P0 conditions.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	

5. The DT updated Requirements R9 – R11 based on comments received. Do you agree with the updated proposed TPL-008-1 Reliability Standard Requirements? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with the modifications in Requirements R9, R10, and R11. These modifications improve the clarity of the standard and, in the case of Requirement R10, make a good change to permit possible actions designed to reduce the likelihood of the event to be considered as well.	
Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD

Answer	No
Document Name	
Comment	

Many of the CHPD concerns from the previous draft redline still exist in this redline version. CHPD believes the updates made to R9 were very good, with a couple concerns remaining. The first concern is to the statement ‘make its Corrective Action Plan available to’ in R9.1. CHPD suggests this be changed to ‘make its Corrective Action Plan available on request’, to align with a similar request-based mechanism under R11. We’ve found the general “make available” is murky language for compliance.

The second concern is the expectation in 9.1 and 9.2 for soliciting feedback and notifications to “regulatory authorities or governing bodies responsible for retail electric service issues”. The intent here is not clear. Could the SDT provide some examples of what is intended here, both for Jurisdictional and non-Jurisdictional entities? Our entity is a Public Utility District – who does the SDT envision we would provide this notification to – our publicly elected commissioners?

It is noted that the R9 Measures now appear to include the solicitation and notification as part of the measures for compliance with R9 which is an improvement from the previous draft version.

Lastly, in Order 896, FERC’s Commission determination in paragraph 157 reads:

“*As stated above, we adopt and modify the NOPR proposal and direct NERC to require in the new or modified Reliability Standard the development of corrective action plans that include mitigation for specified instances where performance requirements for extreme heat and cold events are not met—i.e., when certain studies conducted under the Standard show that an extreme heat or cold event would result in cascading outages, uncontrolled separation, or instability.*”

FERC's directive is when the outcome of studies would result in cascading outages, uncontrolled separation, or instability, a corrective action plan is required. However, in TPL-008, the SDT has gone further. The current state of draft TPL-001-8 R9 states:

"*Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall*:"

The difference here is Order 896 is only requiring corrective action plans for cascading outages, uncontrolled separation, or instability. the SDT is proposing to require corrective action plans for not meeting performance criteria, which also includes normal voltage limits or normal line ratings, even though these exceedances may not result in cascading outages, uncontrolled separation, or instability. The request is for the SDT to align its R9 language with Order 896 paragraph 157 language. These other limits are needed to assess for cascading outages, uncontrolled separation, or instability, but the requirement to develop a corrective action plan for such exceedances is beyond Order 896's request for this proposed standard.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The term, "Non-Consequential Load Loss," is an oxymoron. It is also unrealistic to imagine that load shedding can be limited to a small, tolerable amount. The uncertainties associated with extreme cold weather in particular are so severe that PCs and TPs should be required to serve all load with a sizeable reserve margin.

The expression, "beyond their control," should be replaced with an objective, auditable criterion.

CAPs for winter issues should be required to include early starting of generation units, to help accommodate the additional starting time that may be required during extreme cold weather.

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

The "applicable regulatory authorities or governing bodies responsible for retail electric service" in R9 needs better clarification - what does this look like for jurisdictional vs non-jurisdictional - is this not applicable to non-jurisdictional? Ask of SDT to provide better guidance & examples.

Requirement R10 should explicitly clarify that a Corrective Action Plan is not required for P7 Contingencies, as stated in the previous draft 2, Table 2.1, page 11.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

In the current draft, it is not clear what the time frame is for providing the CAP or soliciting feedback from the regulatory authorities or governing bodies in R9.1. In addition, there is no time frame when to notify the applicable regulatory authorities or governing bodies in R9.2. R9.4 indicates allowing revision to the Corrective Action Plan but does not clarify when and what triggers the revision.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

(R9.1 and R9.2) We recommend that further clarification be given to how "applicable" regulatory authorities or governing bodies are determined. In addition, we believe that soliciting feedback (R9.1) and notification (R9.2) should be replaced with "make available upon request."

(R10) No issues.

(R11) We recommend that the timeframe be extended to 90 calendar days.

Likes 0	
Dislikes 0	

Response

Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	No
Document Name	
Comment	

Requirement #9.3 states:

"Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity documents the situation causing the problem, alternatives evaluated, and takes actions to resolve the situation."

The Extreme Temperature Assessment would have to be performed at least once every 5 years, assessing one year in the Long Term Planning Horizon.

It is recognized that the details of the extreme heat/cold benchmark temperature events may change over time, and that the underlying assumptions utilized in the Extreme Temperature Assessment for one of the years in the Long Term Planning Horizon may change over time. CAPs identified in one Assessment may not be needed in a future Assessment. It may be difficult to pursue expensive CAPs understanding that assumptions may change.

With this in mind, we find it difficult from a compliance perspective to clearly identify what is meant by "in the required timeframe". This language, while allowing for flexibility, seems very ambiguous. The Technical Rationale does not elaborate on this point.

We recommend that the SDT clarify what is intended by "*in the required timeframe."*

Comment on Requirement #11

Requirement #11 states:

"Each responsible entity, as identified in Requirement R1, shall provide its Extreme Temperature Assessment results within 60 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information."

This could be interpreted in different ways.

We would recommend the SDT consider modifying the wording (see TPL-001-5.1 Req #8 for reference) and **timeframe** to be more consistent with TPL-001-5.1 Req #, 8 as follows:

"Each responsible entity, as identified in Requirement R1, shall provide its latest completed Extreme Temperature Assessment results within 90 calendar days of a request to any functional entity that has a reliability related need and submits a written request for the information.

Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No

Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 5

Likes 0	
Dislikes 0	
Response	

Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	

Southern Company supports EEI's comments.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

EEI has no concerns with Requirements R10 and R11, however, we do suggest changes to the subparts of Requirement R9 in order to more clearly define R9.1-R9.3 as being specific to the utilization of 'Non-Consequential Load Loss as an interim solution' and to better align with TPL-001 Attachment 1 III (Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required) with the TPL-008-1 Technical Rationale.

Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1 {C}Be allowed to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1. (*formally 9.4*)

9.2 Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity**:** (*formally 9.3*)

9.2.1 **D**ocuments the situation causing the problem, and **make changes to mitigate the identified problem**. (*extracted from 9.3*)

9.2.2 Documents alternative(s) considered and **notifies the** applicable regulatory authorities or governing bodies responsible for retail electric service issues when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency. *(Moved from old 9.2)*

9.2.3 Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. (*formally 9.1*)

Likes 0	
Dislikes 0	

Response

Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight

Answer	No
Document Name	

Comment

GRE supports the comments of the NSRF and GRE has additional comments

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI has no concerns with Requirements R10 and R11, however, we do suggest changes to the subparts of Requirement R9 in order to more clearly define R9.1-R9.3 as being specific to the utilization of 'Non-Consequential Load Loss as an interim solution' and to better align with TPL-001 Attachment 1 III (Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required) with the TPL-008-1 Technical Rationale.

R9. Each responsible entity, as identified in Requirement R1, shall develop a Corrective Action Plan(s) when the analysis of a benchmark planning case, in accordance with Requirement R8 Part 8.1, indicates its portion of the Bulk Electric System is unable to meet performance requirements for category P0 or P1 in Table 1. For each Corrective Action Plan, the responsible entity shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

9.1 Be allowed to have revisions to the Corrective Action Plan in subsequent Extreme Temperature Assessments, provided that the planned Bulk Electric System shall continue to meet the performance requirements of Table 1. (*formally 9.4*)

9.2 Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted in Table 1, in situations that are beyond the control of the Planning Coordinator or Transmission Planner that prevent the implementation of a Corrective Action Plan in the required timeframe, provided that the responsible entity: (*formally 9.3)*

9.2.1 Documents the situation causing the problem, and makes changes to mitigate the identified problem (*extracted from 9.3)*

9.2.2 Documents alternative(s) considered and notifies the applicable regulatory authorities or governing bodies responsible for retail electric service issues when Non-Consequential Load Loss is utilized as an element of a Corrective Action Plan for a Table 1 P1 Contingency. *(Moved from old 9.2)*

9.2.3 Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues. (*formally 9.1*)

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE believes sensitivity cases are unnecessary and believes Requirement 10.2 should be removed since planning cases are already planned for extreme events. Refer to CEHE's comments in Q3. In the current draft, it is not clear what the timeframe is for providing the CAP in R9.1. In addition, there is no timeframe when to notify the applicable regulatory authorities or governing bodies in R9.2. R9.4 indicates allowing revision to the Corrective Action Plan but does not clarify when and what triggers the revision. R11 - CEHE recommends that the timeframe be extended to at least 90 calendar days.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	No
Document Name	
Comment	

Oncor strongly disagrees with the following statement in R9.1: “Make its Corrective Action Plan available to, and solicit feedback from, applicable regulatory authorities or governing bodies responsible for retail electric service issues.” We propose that “applicable regulatory authorities or governing bodies” be defined and limited. For example, a TP should only need to provide their PC with CAP information.

In addition, we disagree with the following phrase “and notify the applicable regulatory authorities or governing bodies responsible for retail electric service issues” as it relates to Load Shed. The intended regulatory audience needs to be clearly defined.

Oncor disagrees with R10 as well. The requirement does not give TPs the ability to create CAPs for the listed contingencies.

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No

Document Name	
Comment	

- The purpose and required response actions related to the sharing of CAPs and solicitation of feedback is not clear.
- Documentation of alternatives is an additional administrative burden and provides little benefit to reliability. It is also unclear if there is some type of expectation these alternatives are reviewed or potentially challenged as invalid.
- The role of the TO and/or GO in implementing or otherwise responding to CAPs that may require additions or modifications to their systems/facilities is not captured in these requirements.
- There appears to be a significant amount of outside review required but no clear actions the responsible entity is required to take, particularly if there is a dispute. What is the purpose of the review and the expected response? This potentially produces an undue burden on the PC/TP and adds subjectivity in requiring a review with no documented guidelines for conducting the review.
- GTC recommends the restructuring of requirement 9 such that documentation of alternatives along with the sharing and soliciting feedback back is only necessary when utilizing Non-Consequential Load Loss as an interim solution.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	2023-07_Unofficial_Comment_Form_Draft 3_100724 ITC (002).docx

Comment

See attachment with suggested changes.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has multiple concerns around CAPs. The first concern is that the mechanism to issue a CAP for FERC Order 1000 is typically limited in SPP to the Near-Term Transmission Planning Horizon. Secondly, if other SPP planning assessments evaluate extreme weather, SPP would like to consider those CAPs for revision to the CAPs identified in the 5-year extreme temperature assessment. (potential verbiage could include Corrective Action Plan in subsequent Extreme Temperature Assessments or other planning assessments that evaluate extreme weather conditions). This would also help if other transmission projects came to fruition in between the 5-year assessments that could potentially mitigate the need for the CAP in the extreme weather study.

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	
Requirements R9 and R10 both regard obligations of the responsible entity based on inability to meet certain performance requirements. These requirements should be combined into a single requirement (with sub-requirements) to make this aspect of the standard clearer to follow. With respect to Requirement R9 Parts 9.1 and 9.2, it is unclear why Part 9.2 is necessary if the entire Corrective Action Plan is required to be made available to applicable regulatory authorities or governing bodies responsible for retail electric service issues under Part 9.1. Perhaps Part 9.2 should instead be a sub requirement under Part 9.1 that specifies certain information that must be included in the distributed Corrective Action Plan under Part 9.1; otherwise, it may be confusing to the responsible entity how to implement Part 9.1 and Part 9.2 as separate items (including interpreting differences in language such as “make available to” and “solicit feedback from” in Part 9.1 and “document” and “notify” in Part 9.2 directed to the same entities).	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	

a. Requirement R9 should be modified to specify that the expected impact of extreme heat and cold should be accounted for when designing and measuring the impact of the solutions proposed in a Corrective Action Plan (CAP). Many potential solutions in a CAP can have greater or lesser impact under extreme heat or cold conditions. For example, a CAP that relies on adding gas generation can be less effective under extreme heat due to output reductions due to ambient temperature derates, and under extreme cold due to correlated gas generator outages. Gas generator outages due to equipment failures and fuel supply interruptions have accounted for the majority of outages during recent cold snap events.{C}[1] As noted above in response to question 4, FERC's directive in paragraph 89 of Order 896 states that "it is necessary that responsible entities evaluate the risk of correlated or concurrent outages and derates of all types of generation resources and transmission facilities as a result of extreme heat and cold events." On the other hand, CAPs that include demand response and energy efficiency programs related to building HVAC systems can offer contributions that are larger than expected during extreme heat or cold because load associated with cooling or heating is higher during such events.

During extreme cold events, expanded transmission ties with neighboring grid operators can also exceed the benefits they offer under normal conditions because transmission line thermal limits are higher during extreme cold and wind chill conditions. Transmission ties also tend to offer large benefits during extreme heat and cold, as severe weather events tend to be at their most extreme in geographically confined areas, ensuring at least some nearby grid operators are not experiencing shortfalls in generation.[2] The benefits of interregional transmission are even greater at higher renewable penetrations.[3] The value of transmission ties during extreme heat and cold events should be accounted for when assessing baseline performance during benchmark events as well as quantifying the value of expanding these ties as part of a CAP.

The higher transfer capacity of advanced conductors under extreme heat and cold conditions should also be accounted for, as carbon and composite core conductors sag roughly half as much as comparable ACSR conductors. Finally, Grid-Enhancing Technologies like dynamic line ratings, topology optimization, and power flow control devices offer significant benefits when the grid may be congested due to extreme temperatures. Dynamic line ratings are particularly valuable for enabling operators to safely use transmission lines' higher thermal limits during extreme cold and wind chill conditions.

Accounting for how a CAP will fare under the extreme heat or cold conditions it is designed to solve is essential for ensuring reliability. Without accounting for the reduced effectiveness of some CAP elements under extreme heat or cold, planners will be blind to potential reliability risks. In other cases, failing to account for the effectiveness of specific CAP measures under extreme heat or cold will result in a suboptimal selection of solutions. Extreme heat and cold must not only be accounted for in identifying reliability risks, but also designing solutions to those risks.

b. The draft of R9 also includes a potential loophole that a responsible entity could use to avoid implementing a CAP that is needed to address reliability concerns.

First, allowing load curtailment for a P1 contingency under TPL-008 is a major departure from the requirements of TPL-001, which do not allow load shedding for a P1 contingency.{C}[4] Allowing responsible entities plans' to include load shed when they experience a single P1 contingency under extreme heat or cold conditions is contrary to FERC's intent in Order 896 that NERC enact a standard that will ensure reliable operations under extreme heat and cold conditions.

More generally, a major concern with the draft standard is that there is no compliance mechanism to ensure CAPs are implemented. If implementing some CAP solutions requires action by an entity other than the transmission planner or planning coordinator responsible entities, the draft standard should be revised to include such a requirement on those entities. Other draft NERC standards include requirements to implement CAPs, and similar language could be adopted for TPL-008. For example, requirement R9 of the PRC-028 draft requires a generator or transmission owner to "develop, maintain, and implement a Corrective Action Plan to provide the required capability,"{C}[5] and requirement R6 of the PRC-030 draft requires "Each applicable Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5:

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. Notify each applicable Reliability Coordinator if CAP actions or timetables change and when the CAP is completed."[6]{C}

{C}[1]{C} *See, e.g.*, FERC and NERC*, Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (October 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022, at 17; FERC and NERC, *The*

February 2021 Cold Weather Outages in Texas and the South Central United States (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16; FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf; PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

{C}[2]{C} https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

{C}[3]{C} https://www.nrel.gov/docs/fy22osti/78394.pdf

{C}[4]{C} https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf, at 21

{C}[5]{C} https://www.nerc.com/pa/Stand/Project202104ModificationstoPRC0022DL/2021-04_AB_PRC-028-1_Clean_03182024.pdf

{C}[6]{C} https://www.nerc.com/pa/Stand/Project202302PerformanceofIBRsDL/2023-02%20PRC-030-1_032524.pdf

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments toward these requirement drafts.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	

Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports leaving only P7 contingencies in R10	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R9, R10, and R11. Exelon would support the clarification suggested by the EEI for R9. .	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon agrees with the updated proposed TPL-008 Reliability Standard Requirements R9, R10, and R11. Exelon would support the clarification suggested by the EEI for R9.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Based on other projects that include developing and implementing CAPs, USV would feel more confident with the proposed modifications if there were guidelines and more structured timelines set for the CAPs. Perhaps not in the standard itself, but guidance on timelines could be explained in the technical rationale and include timelines for implementing CAPs and when entities can utilize backup action plans such as Non-Consequential Load Loss.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT understands Requirement R9 and Table 1 to allow the use of Non-Consequential Load Loss (NCLL) to address a performance deficiency in a P1 event. ERCOT supports this approach, as the planning cases that TPL-008 addresses are based on extreme grid events that, coupled with a P1 scenario, are unlikely to reflect realistic future system conditions and therefore should not be treated the same way as planning events are treated under TPL-001-5.1. Consistent with this understanding, ERCOT recommends that Part 9.3 be revised as follows to more clearly align with the language in Table 1:	

"9.3. Be permitted to utilize Non-Consequential Load Loss as an interim solution, which normally is not permitted ***for P0 events*** in Table 1…"

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 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	

Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 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	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNMR supports R10 and R11. PNMR supports EEI's proposed changes to R9.1 thru R9.4.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE continues to recommend including a timeframe for which the CAPs need to be developed and submitted for review once the benchmark planning case study results indicate the System is unable to meet performance requirements.

Texas RE likewise continues to have concerns about the submission of CAPs solely to “applicable regulatory authorities…responsible for retail electric service.” As an initial matter, it is unclear how this requirement will work in practice and how the ERO could maintain visibility into the CAP review process. More broadly, since the Reliability Coordinator (RC) is the functional entity responsible for the Reliable Operation of the Bulk Electric System within the NERC jurisdictional model, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations, the CAP should at least be submitted to the RC in addition to applicable regulatory authorities.

Consistent with this approach, Texas RE recommends the following revision:

9.1 Make their CAPs CAP available and solicit feedback from their Reliability Coordinator and applicable regulatory authorities or governing bodies responsible for retail electric service issues within 60 days of developing the CAPs.

Additionally, Texas RE noticed that while Non-Consequential Load Loss is allowed for single and multiple circuit contingencies based on Table 1 performance criteria, the amount of Non-Consequential Load Loss allowed is not specified. This could lead to inconsistent application of load interruptions to maintain system performance.

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	

Comment

R11 is purely administrative in nature and based on previous NERC/industry efforts to remove administrative details it should be removed. Technical rationale provided for R11 seems lacking as to need and essentially could be used for any standard.

Likes 0	
Dislikes 0	

Response

6. The DT believes proposed modifications in TPL-008-1 provide entities with flexibility to meet the reliability objectives in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

Devin Shines – LG&E/KU	
Answer	Yes
Document Name	
Comment	
The modifications in this draft improve entity flexibility while also providing much needed transparency and alignment with FERC directives. The FERC directives in Order 896 will require a significant (and costly) effort to meet. Recognizing the DT must make a standard to meet these directives, the modifications to TPL-008-1 make it effective while also allowing entities flexibility in meeting the reliability objectives.	
Likes 0	
Dislikes 0	
Response	

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	
Comment	
Sensitivity to generation, load and transfers are already studied as part of TPL-001-5.1 yearly for near and long-term scenarios (year 10/year 12). The sensitivity additional studies proposed for R8.2 are unlikely to yield any new information and will be duplicative work for Transmission Planners. The Extreme Temperature Assessment is already a very extreme sensitivity study itself that should already capture modified load, generation, transmission, and transfers befitting this analysis per R3, so it is not needed nor appropriate to study sensitivities for sensitivity cases. Further sensitivity cases to adjust such power flow variables would be a nice idea, but it does not appear cost effective to mandate developing and evaluating “sensitivity” cases in addition to the already sensitive nature if the extreme weather assessment. · If sensitivity cases are deemed necessary, it would be more cost-effective to waive the obligation to study and analyze stability for those sensitivities.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	
Comment	

Being that this is a new assessment, entities will likely have to build additional models, coordinate with appropriate entities, perform the assessment, and train staff, there will likely be a large cost associated with implementation of this standard.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	
Comment	

ITC believes it is not cost effective to build a sensitivity model and analyze the required events yet not require any Corrective Action Plans.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	
Comment	

The attempt for flexibility is appreciated but this standard still falls short of something that is clear and allows the PC/TP to appropriately plan to meet reliability goals. The inclusion of outside entity reviews of CAPs offers the reviewer flexibility as there are no bounds provided to them. The PC/TP, however is potentially subjected to subjective reviews that have no framework with which the PC/TP can effectively respond.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE would be interested in more information on any economic analysis that was performed and believes the new Standard imposes a cost and time burden to PCs/TPs without necessarily providing substantial benefits to the reliability of the BPS.	
Likes 0	
Dislikes 0	
Response	

Joseph Knight - Joseph Knight On Behalf of: Jacalynn Bentz, Great River Energy, 3, 1, 5, 6; - Joseph Knight	
Answer	No
Document Name	
Comment	
GRE supports the comments of the NSRF and GRE has additional comments	
Likes 0	
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
NERC already defines Reliability Coordinator as "The entity that ... has the Wide Area view of the Bulk Electric System...." Rather than asking individual Planning Coordinators and Transmission Planners to coordinated in some ad-hoc, unspecified way, it might be more efficient to assign the responsibility for identifying the weather zones and groups of planning entitites that should coordinate their studies to the Reliability Coordinator, who already has a wide-area vew and is has operational experience with how the power system in their area behaves during temperature extremes.	
Likes 0	
Dislikes 0	
Response	

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
NERC already defines Reliability Coordinator as "The entity that ... has the Wide Area view of the Bulk Electric System...." Rather than asking individual Planning Coordinators and Transmission Planners to coordinated in some ad-hoc, unspecified way, it might be more efficient to assign the responsibility for identifying the weather zones and groups of planning entitites that should coordinate their studies to the Reliability Coordinator, who already has a wide-area vew and is has operational experience with how the power system in their area behaves during temperature extremes.	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
At this time, we are unable to fully agree that this standard provides the necessary flexibility to meet the reliability objectives in a cost-effective manner. We would be interested in more information on any economic analysis that was performed.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy does not provide comments on cost effectiveness of the proposed modifications.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
This consumes resources that could be put to better use in the basic TPL analysis.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The reliability objectives are not being met, ref. our comments above.	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
New Standard requiring extensive coordination with adjacent PCs/TPs within the defined “zones”. New Standards impose a cost and time burden to PCs/TPs without necessarily providing substantial benefits to the reliability of the BPS.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
While the DT is offering flexibility, we request the DT keep this standard from becoming overly prescriptive allowing members to obtain these in a cost effective manner. Until we see the final result from the PC, FirstEnergy cannot fully determine flexibility to meet the reliability objectives in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
The updates to TPL-008 in the Draft 3 redline provide more flexibility for entities to meet the objectives in the standard than previous draft versions. This is best reflected by the removal of R2 language such that R2 no longer requires entities to select a benchmark event from the benchmark library if the selected event meets the requirements described in R2.2.1 and R2.2.2.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kinte Whitehead - Exelon - 3	
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	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,7 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
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	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Broc Bruton On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Broc Bruton	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC leaves comments of the cost-effectiveness to those that must compy with the proposed standard.	

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop

Answer	
Document Name	

Comment

Ameren offers no comment on the cost effectiveness of the project.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

MRO NSRF has no comment on the cost effectiveness of the draft language at this time.

Likes 0	
Dislikes 0	

Response

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

Devin Shines – LG&E/KU	
Answer	
Document Name	
Comment	
This comment form did not include a question to provide feedback on the modifications to Table 1, but LG&E/KU supports all modifications.	
Likes 0	
Dislikes 0	
Response	

Barbara Marion – Dominion Energy	
Answer	
Document Name	
Comment	
The issues deal primarily with the referenced methodology for referenced events as well as the arbitrary nature of dividing the country into study regions based on the objectives of the proposed standard.	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	
Consumers Energy maintains its stance that the SDT must change “Bulk Power System (BPS)” to “Bulk Electric System (BES)” in section A.3. for consistency with the proposed Extreme Temperature Assessment definition and TPL-001 purpose statement.	

“Contingency BES Level” for a Category P0 event in Table 1 should be changed to “N/A” as there are no contingencies to be applied when the Event is “None”. This would provide consistency with the Fault Type listing for the P0 Category as well.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

AEP offers the following additional comments regarding potential overlapping or duplicative obligations.

R1’s “shall complete its responsibilities such that the … assessment is completed…” appears duplicative with R8’s “shall complete steady-state and stability analysis… ”. AEP recommends removing the last sentence from R1 regarding completing the Extreme Temperature Assessment at least once every five calendar years and appending it to R8.

Regarding R5, the TP and PC should already possess steady state voltage criteria to satisfy TPL-001 R5. As a result, AEP recommends removing R5 to avoid compliance risk associated with duplicative obligations. If the drafting team chooses to retain R5, the phrase “shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations” might benefit from something more actionable than “shall have.” AEP recommends the drafting team consider “shall devise” or “shall develop.”

R6’s identification of instability, uncontrolled separation, and cascading per criteria or methodology is already required in TPL-001 R6, which once again appears duplicative and would unnecessarily increase compliance risk. AEP recommends it be removed.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

This includes all changes and/or clarifications requested by Avista

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
We would like to thank the STD for being responsive to the industry concerns and making this proposed standard more flexible for the various entities to conform to.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	
Document Name	
Comment	
• The clean-up of Table 1 to better align with TPL-001-5's Table 1 is noted and appreciated. • The VRF for R5 was changed to "Medium" for this draft 3, however the VRF for R6 was not changed to "Medium". It is requested the VRF for R6 be set as "Medium" for consistency with TPL-008 R5.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	
MRO NSRF has no additional comments.	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	
Document Name	
Comment	
R6 VRF is 'High', but it should be set as 'Medium' to match TPL-008 R5, R7, and TPL 001-5 R6. Corrective Action Plan requirement column should be added back to Table 1, as stated in the previous draft 2, Table 2.1, page 11.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1, Group Name National Grid

Answer	
Document Name	

Comment

National Grid supports EEI's comments and in-addition:

1. Please consider adding clarity regarding Stability Only Events, noting that in TPL-001-5.1 - Item j (Stability Only) was not included in Table 1 of TPL-008-1. It is unclear whether the exclusion of Stability Only events was intentional or an unintentional omission. If this was unintentional, we suggest adding the following:

Page 10 (Stability Only Section – NEW):

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Note: *If adding item j above was an unintentional omission, then we further suggest that the following edits are additionally required in Requirement R5. See below:*

Each responsible entity, as identified in Requirement R1, shall have criteria for acceptable System steady state voltage limits and post-Contingency voltage deviations and the transient voltage response for its system for completing the Extreme Temperature Assessment. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2. Please consider adding a new footnote (Page 12 of Table 1) to better clarify the BES voltage levels for Events and align with Footnote 1 from TPL-001-5.1 (See below)

For P0 and P1 events, the BES level of the event is the lowest System voltage level of the element(s) removed for the analyzed event. For P7 events, the BES level of the event is the highest System voltage level of the element(s) removed for the analyzed event.

Likes 0	
Dislikes 0	

Response

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA suggests that the Violation Risk Factor for R6 be changed from high to medium to be consistent with R5 as well as TPL-001 R5 and R6.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Please see EEI coments	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
The zones identified in draft TPL-008-01, R2 cover large areas with widely varying temperature extremes. Selection of a single temperature event to represent all generators within a zone is not realistic. The draft TPL-008 Tech Rationale acknowledges the limitation of using a single temperature over wide areas. The NERC Standard EOP-12 extreme cold weather drafting teams struggled with the challenge of widely varying temperature conditions across geographical areas and developed the Extreme Cold Weather Temperature (ECWT) as a "good enough" bounding temperature for cold weather preparation planning. These ECWTs have been provided to PCs and TOPs as part of routine data requests from these entities. However, neither the draft TPL-008 Standard or the Tech Rationale appear to include any consideration of the use of ECWT in planning studies, And the terms "extreme cold" and "extreme heat' are not defined in the draft TPL-008 Standard. Suggest the Tech Rationale be revised to include some mention of the generator cold weather planning Standard or the data which the PC / TOP may have requested from generators, as a way to "fine tune" the results of the PC TPL-008 benchmark studies. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	

The zones identified in draft TPL-008-01, R2 cover large areas with widely varying temperature extremes. Selection of a single temperature event to represent all generators within a zone is not realistic. The draft TPL-008 Tech Rationale acknowledges the limitation of using a single temperature over wide areas. The NERC Standard EOP-12 extreme cold weather drafting teams struggled with the challenge of widely varying temperature conditions across geographical areas and developed the Extreme Cold Weather Temperature (ECWT) as a "good enough" bounding temperature for cold weather preparation planning. These ECWTs have been provided to PCs and TOPs as part of routine data requests from these entities. However, neither the draft TPL-008 Standard or the Tech Rationale appear to include any consideration of the use of ECWT in planning studies, And the terms "extreme cold" and "extreme heat' are not defined in the draft TPL-008 Standard. Suggest the Tech Rationale be revised to include some mention of the generator cold weather planning Standard or the data which the PC / TOP may have requested from generators, as a way to "fine tune" the results of the PC TPL-008 benchmark studies.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 7

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the clarification suggested by the EEI for Table 1.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNMR supports EEI's comments related to Table 1 events 1 & 6.	
Likes 0	
Dislikes 0	
Response	

Robert Jones - Seattle City Light - 1,3,4,5,6	
Answer	
Document Name	
Comment	
As stated above, since this standard requires entities come to a consensus on scenarios and and coordination methodology within each zone, there should be some method of deispute resolution to ensure that process can be completed successfully.	
Likes 0	
Dislikes 0	
Response	

Sharon Darwin - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Southern Company supports the additional comments provided by EEI. Southern greatly appreciates the efforts of the SDT to address and incorporate industry feedback and is very encouraged by the changes made in recent drafts.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	

Comment

EEI suggests the following changes to Table 1 – Steady State & Stability Performance Events as follows:

Formatting issue with P7 (Sensitivity Cases): The "Yes" statement is out of alignment with the other cells.

Page 10 (Steady State only Section)

Item h. from TPL-001-5.1 should be added to Table 1 of TPL-008-1 (see below):

h. Planning event P0 is applicable to Steady State only.

EEI asks for clarity regarding Stability Only Events, noting that in TPL-001-5.1 - Item j (Stability Only) was not included in Table 1 of TPL-008-1. It is unclear whether the exclusion of Stability Only events was intentional or an unintentional omission. If this was unintentional, we suggest adding the following:

EEI offers the following edits to Footnote 1 (Page 12), which we believe provides greater clarity to the footnote (proposed changes in boldface below including first sentence removed):

For P1 events, the BES level of the event **is determined by the lowest System voltage level of the elements(s) removed for the analyzed event.** For P7 events, the BES level of the event is determined by the highest System voltage level of the element(s) removed for the analyzed event.

EEI suggests that Footnote 6 (Page 12) be modified by deleting the first sentence because it is duplicative of the language already contained in Requirement R9. See below (*First Sentence Removed*):

In benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and requires notification of applicable regulatory authorities or governing bodies responsible for retail electric service issues when utilized as an element of a Corrective Action Plan for P1 Contingencies. *See Requirement R9 for the relevant requirements.*

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

Michael Brytowski - Great River Energy - 3

Answer	
Document Name	

Comment

The current ordering of requirements R1, R2, & R3 creates confusion when reading the responsibilities of requirements 4-11. Consider reordering – R2, R3 then R1. Coordinating Zones, develop benchmark planning then conducting the assessments. The Transmission Planner (TP) is not referenced in R2 or R3.

R2 currently – Coordinating Zones

Each Planning Coordinator shall identify the zone(s) to which the Planning Coordinator belongs to under Attachment 1, and shall coordinate with all Planning Coordinators within each of its identified zone(s), to select one common extreme heat benchmark temperature event and one common extreme cold benchmark temperature event for each of its identified zone(s) when completing the Extreme Temperature Assessment.

R3 currently – a process for developing benchmark planning

Each Planning Coordinator shall coordinate with all Planning Coordinators within each of its zone(s) identified in Requirement R2, to implement a process for developing benchmark planning cases for the Extreme Temperature Assessment that represent the benchmark temperature events selected in Requirement R2 and sensitivity cases to demonstrate the impact of changes to the basic assumptions used in the benchmark planning cases.

R1 currently – The assessments

Each Planning Coordinator shall identify, in conjunction with its Transmission Planner(s), each entity's individual and joint responsibilities for completing the Extreme Temperature Assessment, which shall include each of the responsibilities described in Requirements R2 through R11. Each responsible entity shall complete its responsibilities such that the Extreme Temperature Assessment is completed at least once every five calendar years.

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment	

Our understanding of the Benchmark Process is that the Weather Zones were used to develop the lists (library) of Benchmark Events, and therefore each Weather Zone has its library. Our interpretation of the current document would be that Québec shares the same library "Eastern Canada" as our Canadian neighbors, without however having to choose the same events every 5 years because we are alone in our ETA Zone as per the table in Attachment 1.

However, the Quebec zone vs. Eastern Canada zone should be clarified because the Technical Rationale does not distinguish between the two types of zones (Weather Zones and ETA Zones), and rather gives the impression that it would normally be the same zone while the list under "Benchmark Event Data" on the Project page give the impression that the Québec zone is included with the Eastern Canada zone. To be consistent with the table and the map in Attachment 1, if we decided that we did not need to coordinate with our neighbors for the ETA, there is no reason for us to share the same library, Québec should have a separate library.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI suggests the following changes to Table 1 – Steady State & Stability Performance Events as follows:

Formatting issue with P7 (Sensitivity Cases): The “Yes” statement is out of alignment with the other cells.

Page 10 (Steady State only Section)

Item h. from TPL-001-5.1 should be added to Table 1 of TPL-008-1 (see below):

h. Planning event P0 is applicable to Steady State only.

EEI asks for clarity regarding Stability Only Events, noting that in TPL-001-5.1 - Item j (Stability Only) was not included in Table 1 of TPL-008-1. It is unclear whether the exclusion of Stability Only events was intentional or an unintentional omission. If this was unintentional, we suggest adding the following:

EEI offers the following edits to Footnote 1 (Page 12), which we believe provides greater clarity to the footnote (proposed changes in boldface below):

For P1 events, the BES level of the event is determined by the lowest System voltage level of the elements(s) removed for the analyzed event. For P7 events, the BES level of the event is determined by the highest System voltage level of the element(s) removed for the analyzed event.

EEI suggests that Footnote 6 (Page 12) be modified by deleting the first sentence because it is duplicative of the language already contained in Requirement R9. See below:

In benchmark planning cases, Non-Consequential Load Loss is not permitted for category P0 and requires notification of applicable regulatory authorities or governing bodies responsible for retail electric service issues when utilized as an element of a Corrective Action Plan for P1 Contingencies. *See Requirement R9 for the relevant requirements.*	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2023-07 TPL-008-1 Draft #3	
Answer	
Document Name	
Comment	

For purposes of posterity, the SRC requests the standard drafting team provide a supporting explanation in the Technical Rationale justifying why P1 and P7 events are limited to >200 kV. Consider revising the Extreme Temperature Assessment definition to make it easier to read. The SRC proposes the following language:

Extreme Temperature Assessment – Documented ***benchmark and sensitivity*** evaluation of future Bulk Electric System performance for extreme heat and extreme cold benchmark temperature events.

The SRC recommends adding language for clarity of the number of cases needed. As currently drafted, TPL-008 R2 (winter / summer), R3 (benchmark / sensitivity), R4 & R5 (power flow), and R6 (dynamics) requires eight cases, however, this information is not straight forward and may lead to missed cases.

The SRC requests clarification regarding R3.3 [Assumed seasonal and temperature dependent adjustments for Load, generation, Transmission, and transfers in areas outside the zone, as needed.] In the event an area is lacking in resources to meet an extreme future case load, is the PC to assume reliance on neighboring zones to import (and assume import capability) or can the CAP be to establish more resources (dependency or self-sufficiency)?

Please confirm that the PC selects which future year (within the long-term planning horizon) is studied, as long as it is greater than one year.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports the clarification suggested by the EEI for Table 1.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Attachment 1 – Extreme Temperature Assessment Zones in accordance with Requirement R2: We agree with Québec being its own Interconnection in the map and in the table, however Québec is the only area that has its own zone in the table which does not correspond to a Weather Zone identified in the Benchmark Process. Similarly, it is not in the list of benchmark temperature event data on the project page under “Benchmark Event Data”. For example, ERCOT is identified as its own Interconnection and has its own list of benchmark temperature events. Another example is Florida in the SERC region warrants a separate treatment and has its own benchmark temperature event data.

Our understanding of the Benchmark Process is that the Weather Zones were used to develop the lists (library) of Benchmark Events, and therefore each Weather Zone has its library. Our interpretation of the current document would be that Québec shares the same library "Eastern Canada" as our Canadian neighbors, without however having to choose the same events every 5 years because we are alone in our ETA Zone as per the table in Attachment 1.

However, the Quebec zone vs. Eastern Canada zone should be clarified because the Technical Rationale does not distinguish between the two types of zones (Weather Zones and ETA Zones), and rather gives the impression that it would normally be the same zone while the list under "Benchmark Event Data" on the Project page give the impression that the Québec zone is included with the Eastern Canada zone. To be consistent with the table and the map in Attachment 1, if we decided that we did not need to coordinate with our neighbors for the ETA, there is no reason for us to share the same library, Québec should have a separate library.

Lastly, the Quebec zone does not appear in the TPL-008 Attachment 1 map, while it is in the table just above. We suggest adding the label “Québec” or “Quebec Interconnection” in white font in the dark blue space represented by the province of Quebec.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	Project 2023-07 TPL-008 Draft 3 Near Final Comments Rev. 0d 10_18_2024 (1).docx

Comment

Refer to Edison Electric comments.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	
Document Name	

Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	
Comment	

Additional comments regarding the listed requirements are as follows:

R5:

• The recently adopted NERC Glossary term, System Voltage Limits, should be referenced in this requirement instead of the outdated wording “System steady state voltage limits”. “…shall have criteria for acceptable System Voltage Limits …”

• Since this requirement appears to refer to steady-state voltage, the post contingency voltage deviation portion of the existing requirement should be removed. The resultant steady-state voltage level being outside of acceptable high and low limits is the point of concern. For example, if a low voltage criterion is 0.92 p.u., then voltages below this limit would violate this particular criterion regardless of whether the beginning voltage was 0.95 p.u., 0.98 p.u., or any other voltage level.

R6:

• The inclusion of “within an Interconnection” is not appropriate as the PC or TP should not be required to assess outside of its applicable area. Note the inclusion of more appropriate language referring to the PC’s or TP’s planning area (its portion of the Bulk Electric System) in this draft so it is not clear why some requirements refer to an Interconnection while others, more correctly, refer to the area of actual responsibility for the PC or TP.

• The following bullet contains a wording addition to clarify the applicability of this requirement to System-wide impacts. This is also consistent with wording in other Reliability Standards when referencing these types of impacts.

• “Each responsible entity, as identified in Requirement R1, shall define and document the criteria or methodology used in the Extreme Temperature Assessment analysis to identify instability, uncontrolled separation, or Cascading of the Bulk Electric System.”

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	2023-07_Unofficial_Comment_Form_Draft 3_100724 ITC (002).docx

Comment

See attachment

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - ReliabilityFirst - 10 - RF

Answer	
Document Name	

Comment

The wording in R6 is similar to CIP-014 in that it could be more prescriptive in describing how an entity should study instability, uncontrolled separation, or Cascading within an Interconnection. ReliabilityFirst and the other regions will assess the validity of judgments made by Registered Entities when assessing this requirement.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	
Document Name	

Comment

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	
Document Name	

Comment

We appreciate the Implementation Plan shortening of the compliance timeline for requirements R2-11 by one year. However, even with that change, the draft Implementation Plan proposes that requirements R7-R11, which require the Extreme Temperature Assessment and any resulting Corrective Action Plan and therefore constitute the substantive requirement of TPL-008, do not take effect until more than 5 years after the Standard is approved by FERC. While this is an improvement relative to the 6-year delay in the prior draft, this timeframe is still excessive. This unnecessary delay is contrary to FERC's directive in Order 896 and the urgent importance of planning for extreme heat and cold events.

NERC's 2023 State of Reliability Overview concluded that "extreme weather events continue to pose the greatest risk to reliability due to the increase in frequency, footprint, duration, and severity." FERC Order 896 was also clear that the increasing frequency and magnitude of extreme weather events "have created an urgency to address the negative impact of extreme weather on the reliability of the Bulk-Power System" (at paragraphs 21-22). Waiting until 2030 to address the largest threat to grid reliability does not make sense. Such a delay is also unnecessary, as entities responsible for TPL-008 already conduct nearly all of the elements of TPL-008 today to comply with TPL-001. TPL-008 effectively requires running similar analyses as TPL-001, but for extreme heat and cold scenarios. As a result, it should be straightforward for responsible entities to modify their existing planning practices to incorporate the two additional scenarios.

This unnecessary delay is also at odds with FERC's directive in Order 896. At paragraph 188, FERC directed "NERC to propose an implementation timeline for the new or modified Reliability Standard, with implementation beginning no later than 12 months after the effective date of a Commission order approving the proposed Reliability Standard." Under the draft Implementation Plan, the only requirement of TPL-008 that comes close to falling within the 12-month timeline FERC directed is compliance with R1, which begins “the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority’s order approving the standard.”

More importantly, R1 only requires that “Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall determine and identify each entity’s individual and joint responsibilities for performing the studies needed to complete the Extreme Temperature Assessment,” and as such is a minor procedural step towards implementing the actual Extreme Temperature Assessment and any resulting Corrective Action Plan in R7-R11. As noted above, those meaningful requirements do not begin until more than 5 years after the standard is approved by FERC in the current draft. To comply with FERC’s directive and the urgency of addressing extreme weather events, the drafting team should require compliance with R7-R11 to begin at the effective date of the standard (around 12 months after FERC approval of the standard), and the interim steps in R2-R6 should also be moved up from the current Implementation Plan’s proposed deadline of 24 months after the effective date of the standard.

Likes 0	
Dislikes 0	

Response