Comment Report

Project Name:	2019-01 Modifications to TPL-007-3
Comment Period Start Date:	7/26/2019
Comment Period End Date:	9/9/2019
Associated Ballots:	2019-01 Modifications to TPL-007-3 TPL-007-4 IN 1 ST

There were 66 sets of responses, including comments from approximately 133 different people from approximately 98 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT approach was to modify Requirement R7.4 to meet the directive in Order 851 to require prior approval of extension requests for completing corrective action plan tasks. Do you agree that R7 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

2. The SDT approach was to add Requirement R11 to meet the directive in Order No. 851 to "require corrective action plans for assessed supplemental GMD event vulnerabilities." R7 and R11 are the same language applied to the benchmark and supplemental events respectively. Do you agree that R11 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

3. Do you agree that the Canadian variance is written in a way that accommodates the regulatory processes in Canada? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order while accommodating Canadian regulatory processes.

4. Do you agree that the standard language changes in Requirement R7, R8, and R11 proposed by the SDT adequately address the directives in FERC Order No. 851? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

5. Do you have any comments on the modified VRF/VSL for Requirements R7, R8, and R11?

6. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

7. The SDT proposes that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

8. Provide any additional comments for the standard drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aubrey Short	4		FE VOTER	Ann Carey	FirstEnergy	6	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aubrey Short	FirstEnergy	4	RF
Electric Reliability Council of Texas, Inc.	Brandon Gleason	2		ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Bobbi Welch	Midcontinent Independent System Operator	2	MRO
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					John Shaver	Arizona Electric Power Cooperative	1	WECC

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	MRO
Public Utility District No. 1 of Chelan County	Joyce Gundry	3		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Davis Jelusich	Public Utility District No. 1 of Chelan County	6	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
Entergy	Julie Hall	6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Adrianne Collins	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern	6	SERC

						Company Generation		
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no NGrid and NYISO	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC

					Shivaz Chopra	New York Power Authority	5	NPCC
					Mike Forte	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Ashmeet Kaur	Con Ed - Consolidated Edison	5	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
PSEG	Sean Cavote	1,3,5,6	FRCC,NPCC,RF	PSEG REs	Tim Kucey	PSEG - PSEG Fossil LLC	5	NPCC
					Karla Barton	PSEG - PSEG Energy Resources and Trade LLC	6	RF
					Jeffrey Mueller	PSEG - Public Service Electric and Gas Co.	3	RF
					Joseph Smith	PSEG - Public Service Electric and Gas Co.	1	RF
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Jamison Cawley	Nebraska Public Power District	1	MRO

1. The SDT approach was to modify Requirement R7.4 to meet the directive in Order 851 to require prior approval of extension requests for completing corrective action plan tasks. Do you agree that R7 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD does not agree with replacing the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis. Since R7.4 is for “situations beyond the control of the entity,” it does not matter if the extensions are considered on a case-by-case basis as the entity will not be able to comply with the CAP timeline as the situation was beyond their control. Adding the case-by-case basis would increase the administrative burden to entities while adding very little benefit to the reliability of the BPS.	
Likes 6	Orlando Utilities Commission, 1, Staley Aaron; Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	

The addition of the ERO for approving any timeline extension may prove to be excessive and burdensome for NERC, and possibly the responsible entity as well. The District recommends an additional statement where the ERO has 60 days to provide notice to the responsible entity when a CAP submittal with an extension request will require ERO approval following full review. Otherwise, if NERC acknowledges receipt with no further notice to the responsible entity, the CAP and extension request is automatically approved. This would reduce the work load on NERC regarding CAPs with extension requests that are minimal or otherwise considered low risk to the BES.

Additionally, there is no consideration of cost. It is possible that a CAP could be expensive and difficult to develop a four-year plan without hindering other more important Transmission Planning objectives in compliance to TPL-001.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Reclamation recommends Requirement R7 be phrased in terms of a responsible entity's required action, not an action required by a CAP.

Reclamation also recommends restructuring TPL-007 so that one requirement in TPL-007 addresses corrective action plans for both benchmark and supplemental GMD Vulnerability Assessments. Reclamation offers the following language for this requirement (see the response to Question 2 regarding the numbering):

R10. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 or the Supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met.

10.1. The responsible entity shall develop the CAP within one year of completion of the benchmark GMD Vulnerability Assessment or Supplemental GMD Vulnerability Assessment.

10.2. The CAP shall contain the following:

10.2.1. A list of System deficiencies and the associated actions needed to achieve required System performance.

10.2.2. A timetable, subject to the following provisions, for implementing each action identified in 7.2.1:

10.2.2.1. Any implementation of non-hardware mitigation must be complete within two years of development of the CAP; and

10.2.2.2. Any implementation of hardware mitigation must be complete within 4 years of development of the CAP.

10.3 The responsible entity shall provide the CAP to the following entities within 90 days of development, revision, or receipt of a written request

10.3.1. Reliability Coordinator;

10.3.2. Adjacent Planning Coordinator(s);

10.3.3. Adjacent Transmission Planner(s);

10.3.4. Functional entities referenced in the CAP; or

10.3.5. Any functional entity that submits a written request and has a reliability-related need for the CAP.

10.4. If a recipient of a CAP provides documented comments about the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

10.5. If a responsible entity determines it will be unable to implement a CAP within the timetable provided in part 7.2.2, the responsible entity shall:

10.5.1. Document the circumstances causing the inability to implement the CAP within the existing timetable;

10.5.2. Document the reason those circumstances prevent the timely implementation of the CAP (including circumstances beyond the entity's control);

10.5.3. Document revisions to the actions identified in part 7.2.1 and the timetable in part 7.2.2; and

10.5.4. Submit a request for extension of the revised CAP to the ERO.

Regarding R10.2.2, Reclamation recommends against mandating industry-wide timelines due to the differences in each entity's capabilities to meet deadlines. For example, the differences in procurement processes and timelines among entities.

Regarding R10.5, Reclamation recommends the standard describe an extension policy. Regional entities may not be capable of fully researching the entire interconnection in order to provide adequate approvals. Reclamation recommends the regional entities or the ERO automate the CAP tracking process.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	

Comment

Please see comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment	
EEI supports the language in Requirements R7.3 and R7.4 believing the proposed changes meet the intent of Order 851. However, the companion process document (i.e., Draft TPL-007-4 CAP Extension Request Review Process) needs additional details to ensure efficient processing of entity CAP Extension Requests, including: 1. A process flow diagram documenting the CAP Extension Process and roles and responsibilities of participants, including the ERO and its authority in this process. 2. NERC contact information where companies can quickly and efficiently check the status of their CAP Extension Requests. 3. Defined deadlines for the completion of CAP Extension Request reviews by NERC and responding to entity inquiries. 4. A process for extending a CAP review deadline for situations where NERC may need additional time. 5. Criteria for a CAP Extension Request 6. An appeals process for denied CAP Extension Requests. 7. A formal process to notify entities on the final ruling for all CAP Extension Requests. 8. Identification of who has oversight of the process within the ERO. While EEI recognizes that the SDT is still early in the development phase of the TPL-007-4 Reliability Standard, we believe it is important to emphasize that having a strong CAP Extension Request process is crucial to ensuring that the directed CAPs are effectively and efficiently processed, similar to the BES Exceptions Process (see Rules of Procedure, Appendix 5C; Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System).	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon agrees with EEI's comments. Exelon believes that the SDT has proposed changes to Requirements R7.3 and R7.4 that meet the intent of the FERC directive in Order 851 but feel it requires further modifications. The Draft TPL-007-4 CAP Extension Request Review Process does not provide the requesting entity with a clear understanding of how the request will be considered, when a decision can be expected, and how an entity could request reconsideration if an extension is denied. With the FERC directive requiring ERO involvement in this case, this justifies placing an obligation on the ERO. The development of a well-defined process similar to the Technical Feasbility Exception Process or the BES Exceptions Process should be concurrently developed and submitted along with the proposed standard to facilitate NERC's engagement. This will provide a mechanism to address the key items noted in EEI's comments. On Behalf of Exelon: Segments 1, 3, 5, 6	

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 1 by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE

Answer	No
Document Name	

Comment

This requirement gives responsibility to an entity which is not an applicable entity under the Standard. The requirement as written also has no impact on reliability, it is purely an administrative requirement and does not directly provide the entitiy with an approved extension. There should be a requirement added which requires the entity that receives the request for CAP extension approve the request within a specified timeframe.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees the modifications to R7.4 meet the directive in FERC Order. No. 851 by replacing the corrective action plan time-extension provisions in R7.4 with a process that extensions of time are considered on a case-by case basis.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 1	Grand River Dam Authority, 3, Wells Jeff
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Yes, the proposed TPL-007-4 Requirement R7, Part 7.4 meets the directive of FERC Order No. 851, Paragraph 54. The FERC directive is extremely narrow and the Project 2019-01 SDT has met the intent to require a process to consider time extensions on a case-by-case basis. However, the FERC directive did not demand that the ERO be the adjudicating entity for time extensions and we suggest the following revision to each ERO reference in the proposed TPL-007-4: "ERO, or its delegated designee." We believe that this modification will allow Regional Entities or other designees to better adjudicate CAP time extensions given their closer proximity, System expertise, and existing Compliance Program obligations.	
Likes 1	Orlando Utilities Commission, 1, Staley Aaron
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Do you agree that R7 meets the directive? my possible answer is NO. **Please see EEI's comments**	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes

Document Name	
Comment	
The proposed language meets the FERC directive.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA understands that the SDT had to respond with proposed changes to meet the directive for R7. BPA does not agree that entities should have to request approval from the ERO for an extension to the Corrective Action Plan for circumstances that occur beyond the entities control. BPA would like to utilize the new ERO Portal tool to allow NERC and the Commission immediate access in real time to the corrective action plan extensions and the justification for the extension. Retaining the requirement as written gives entities the flexibility to respond to unanticipated circumstances without the administrative burden of seeking an extension from NERC. NERC and the Commission would be able to determine if entities are abusing this flexibility and if abuse occurs, should seek to remedy at that time.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
I agree that the language meets the directive, but would it make more sense for the standard to assign this to the regional entities instead of the ERO?	
Likes 0	
Dislikes 0	

Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
PSEG supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Agree that R7 meets the directive. Do not agree that Part 7.4 should require the request for extension be submitted to the ERO for approval. It makes more sense the request be submitted to the Regional Entity.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Eversource agrees with the modification of Requirement R7.4 to meet the directive of Order No. 851. However, Eversource does note that the proposed R7 "approval for any extension" does not provide a mechanism to appeal a denied extension. Additionally, Eversource notes that the proposed "approval for any extension" would come from the ERO while approval from a PC or RC would seem to be more appropriate as they are aware of local limitations which may be the basis for the needed extension.	
Likes 0	

Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	Project 2019-01 Comment Form Attachment.docx
Comment	

ISO/RTO Council Standards Review Committee members ERCOT, MISO, NYISO, PJM, and SPP (the "SRC") submit the following comments regarding Project 2019-01 Modifications to TPL-007-3.

The SRC agrees that the revisions to Requirement R7 proposed by the SDT satisfy FERC's directive in Order 851 regarding extensions of time to implement corrective action plans on a case-by-case basis. In order to further streamline Requirement R7 and more closely align Requirement R7 to the specific language in FERC's directive, the SRC offers the proposed revisions described below and identified in the attached for consideration by the SDT.

In connection with Part 7.3, mentioning the ERO approval processes is not necessary given that Part 7.4 addresses the process. Deleting the reference ("ERO approval for any extension sought under") would result in a more streamlined requirement, and would more closely align with FERC's directive that *Part 7.4* be modified to incorporate the development of a timely and effective extension of time review process. This proposed revision to the current draft of Part 7.3 proposed by the SDT is identified in the attached redline.

In connection with Part 7.4, the SRC suggests the SDT consider:

1. Including express language that an extension of time is “subject to the approval of NERC and the reliability entity’s Regional Entity(s) on a case-by-case basis” in order to more closely align Part 7.4 with FERC’s specific directive that Part 7.4 be modified and that requests for extension of time are to be reviewed on a “case-by-case basis.”

2. Utilizing “NERC and the reliability entity’s Regional Entity(s)” instead of “ERO” in order to more closely align with the specific language utilized in Order 851.

3. Including “of time” in order to more clearly articulate what type of extension is available under Part 7.4

These proposed revisions to the current draft of Part 7.4 proposed by the SDT are identified in the attached redline.

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the standard drafting team's (SDT) efforts to meet the FERC directives. Texas RE has a few concerns as to how the SDT approached the directives.

First, Texas RE is concerned with the following language in Part 7.4:

Additionally, Texas RE is concerned with the ERO's role involving the process for granting CAP extensions. Texas RE asserts that it may be more appropriate to keep operational aspects of the BPS within the hands of the owners/operators and simply make the ERO aware of the CAP. For example, Texas RE suggests that the RC is the appropriate entity to accept/approve the extensions for CAPs. In addition, there could also be a requirement for the registered entity to inform its CEA of a CAP extension. This way, the ERO can verify compliance as far as the RC reviewing extensions of the CAPs and the ERO would not become part of the compliance evaluation and processes of the standard by not having to verify that they themselves reviewed the CAP extension. Moreover, this is consistent with Reliability Standard PRC-012-2 Requirement R6, which requires the RAS-entity submit the CAP to its reviewing RC as the RC has the relevant expertise to review the CAP.

- Part 7.4.1 requires entities to document how circumstances causing delay are beyond the control of the responsible entity, but Part 7.4 does not include language to specify that an extensions are only allowed when “situations beyond the control of the responsible entity [arise].” (FERC Order No. 851). Texas RE recommends updating Part 7.4 to include requirements for extension so implementation issues do not get categorized as documentation issues under Part 7.4.1.

- Part 7.4 only specifies that CAP extensions shall be submitted but does not include language requiring that CAP extensions be approved. While the Draft TPL-007-4 CAP Extension Request Review Process, which is outside of the requirement language, sates “All CAP extension requests must be approved the ERO Enterprise prior to the original CAP completion date”, it may be helpful to specify the timetables for extension requests in relation to the timetables for implementation in the original CAP to avoid scenarios in which the responsible entity submits an extension request immediately prior to the planned implementation date.

- Neither the requirement nor the Draft TPL-007-4 CAP Extension Request Review Process indicate what shall occur if a CAP extension request is not approved.

-

Likes 0	
Dislikes 0	

Response

2. The SDT approach was to add Requirement R11 to meet the directive in Order No. 851 to "require corrective action plans for assessed supplemental GMD event vulnerabilities." R7 and R11 are the same language applied to the benchmark and supplemental events respectively. Do you agree that R11 meets the directive? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
Comment is the same as question #1.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	

Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 2 by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon agrees with EEI's comments and believes that the same concerns expressed in the response to Question 1 are applicable to R11 as well. On Behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA supports comments submitted by AEP for Question #2.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports the language in Requirements R11 believing the proposed changes meet the intent of Order 851. However as stated in more detail in our response to Question 1, the companion process document (i.e., Draft TPL-007-4 CAP Extension Request Review Process) needs to include additional details to ensure effective and transparent processing of entity CAP Extension Requests.

Likes 0	
Dislikes 0	

Response
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	

Comment
Please see comments submitted by EEI.

Likes 0	
Dislikes 0	

Response
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer	No
Document Name	

Comment
PSEG supports EEI's comments.

Likes 0	
Dislikes 0	

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

Answer	No
Document Name	

Comment

Reclamation recommends combining the TPL-007 CAP requirements in R7 and R11 as provided above in response to Question 1. If Reclamation's proposal is accepted, Reclamation recommends restructuring and renumbering the requirements in TPL-007 as follows:

R1 through R6 – no change

R7 – remove and combine CAP language with existing R11

R8 – renumber existing R8 to R7

R9 – renumber existing R9 to R8

R10 – renumber existing R10 to R9

R11 – combine CAP language from existing R7; renumber the new single CAP requirement to R10

R12 – renumber existing R12 to R11

R13 – renumber existing R13 to R12

This will improve the logical flow of the activities required by the revised standard. Reclamation also recommends the SDT add a heading between the new M9 and R10 for "Corrective Action Plans" for consistency with the existing headings "Benchmark GMD Vulnerability Assessments" between M3 and R4, "Supplemental GMD Vulnerability Assessments" between M7 and R8, and "GMD Measurement Data Processes" between M11 and R12.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

ACES believes that the directive could have been dealt with in a less onerous way that addresses concerns other entities have expressed, in their comments, about the potential for duplication of effort between the baseline corrective action plans and supplement corrective action plans. To alleviate some of that potential, the standard could expressly state that corrective action plans are only required for supplemental GMD Vulnerability Assessments, if the corrective actions plans identified for the baseline GMD Assessments do not already address any additional vulnerabilities identified by the supplemental GMD Assessments.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No

Document Name	
Comment	

Comments: NIPSCO does not agree with the Requirement R11 that requires development and implementation of Corrective Action Plan (CAP) for Supplemental GMD events. Judging by the reference geoelectric field values to be utilized for the Supplemental event, the effort appears to be duplicative of the benchmark GMD event (8V/km) with a higher magnitude of 12V/km. As such, we believe the supplemental event represents an “extreme” version of a case that will be assessed under the defined benchmark event.

As corrective action plans are to be developed and implemented for the benchmark GMD event(Requirement R7), requiring CAP for Supplemental event will unnecessarily burden companies for cases that represents an extreme system condition and is not the best cost effective approach to meet the FERC directive

Likes 0	
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3

Answer	No
Document Name	
Comment	

See question one.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

See EEI's comments.

Likes 0	
Dislikes 0	
Response	

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

CHPD does not agree with requiring the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. Entities have only just begun the process of evaluating the benchmark GMD event and developing mitigation measures. The industry is in the preliminary stages of assessing and developing mitigation measures for GMD events and has not had much time to develop engineering-judgement, experience, or expertise in this field. Revising the standard to include CAPs for the supplementary GMD event is not appropriate at this time as the industry is still building a foundation for this type of system event analysis and exploring mitigation measures. Without a sound foundation developed, requiring CAPs for the supplemental GMD event could lead to unnecessary mitigation measures and an immense amount of industry resources spent on a still developing science. CHPD suggests that the benchmark GMD event be fully vetted before moving onto additional scenarios such as the supplemental event.

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While some aspects of R11 may indeed meet the directives as ***literally*** stated in Order No. 851, we do not believe it is a prudent way to meet the ***spirit*** of those directives. We believe R11 is unnecessarily duplicative of the obligations already required for the benchmark event, and disagree with its inclusion. In addition, the obligation to "specify implementation" of mitigation may not be consistently interpreted among entities, and as a result, may not meet the directives for reasons we will provide in this response.

It is our view that the original purpose of the supplemental event was to investigate the impact of local enhancement of the generated electric field from a GMD event on the transmission grid. This requires industry to take an approach in which the GICs are calculated with the higher, enhanced electric field magnitude of 12 V/km (adjusted for location and ground properties) applied to some smaller defined area while outside of this area the benchmark electric field magnitude of 8 V/km (also adjusted for location and ground properties) is applied. This smaller area is then systematically moved across the system and the calculations are repeated. This is necessary as the phenomenon could occur anywhere on the system. Using this Version 2 methodology, every part of the system is ultimately evaluated with the higher electric field magnitude.

In our view, the supplemental event represents a more extreme scenario. Referring to Attachment 1 of the proposed standard, the section titled '**Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event**' provides examples of applying the localized peak geoelectric field over the planning area. The first example presented is applying the peak geoelectric field (12 V/km scaled to planning area) over the entire planning area. This example is a more severe condition than the benchmark event, and should alleviate the need to study the benchmark event if used. In addition, modeling tools for conducting GMD vulnerability studies for the supplemental event using the moving box method have not yet been developed. As such, adding a corrective action plan requirement to the supplemental event obviates the need for studying the benchmark event. Rather than pursuing a Corrective Action Plan for the existing Supplemental GMD Vulnerability Assessment, we believe the SDT should instead pursue only one single GMD Vulnerability Assessment using a reference peak geoelectric field amplitude not determined solely by non-spatially averaged data. This would be preferable to requiring two GMD Vulnerability Assessments, both having Corrective Action Plans and each having their own unique reference peak geoelectric field amplitude. When the Supplemental GMD Vulnerability Assessment was originally developed and proposed, there was no CAP envisioned for it. Because of this, one could argue the merits of having two unique assessments, as each were different not only in reference peak amplitude, but in obligations as well. What has now been proposed in this revision however, is essentially having two GMD Vulnerability Assessments requiring Corrective Action Plans but with different reference peak geoelectric field amplitudes (one presumably higher than the other). It would be unnecessarily burdensome, as well as illogical, to have essentially the same obligations for both a baseline and supplemental vulnerability assessment. In addition to its duplicative nature, it is possible that the results from a benchmark study may even differ or conflict with the results from a given supplemental study.

While the NOPR directs the standard to be revised to incorporate the "development and completion of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities", we find rather that R11 requires the entity "specify implementation" of mitigation. This could be interpreted by some as simply specifying what actions are to be taken but without explicit bounds or expectations on when the final execution of that implementation (i.e. "completion") would take place.

Once again, we believe a more prudent path for meeting the directive would be for the SDT to work with industry and determine an agreeable reference peak geoelectric field amplitude for a single GMD Vulnerability Assessment (benchmark), one not determined solely by non-spatially averaged data, and that potentially requires a Corrective Action Plan. This would serve to both achieve the spirit of the directive, as well as avoid unnecessary duplication of efforts that provide no added benefit to the reliability of the BES.

Likes 1	Grand River Dam Authority, 3, Wells Jeff
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007

Answer	Yes
Document Name	

Comment

The SRC agrees that adding Requirement R11, which is based on the existing language of Requirement R7, satisfies FERC's directive in Order 851 regarding the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities. To the extent the SDT incorporates in Requirement R7 the SRC's suggested revisions identified in response to Question No. 1 above, the SRC proposes the SDT make the same revisions to Requirement R11.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Eversource agrees with the addition of Requirement R11 to meet the directive of Order No. 851. However, Eversource does note that the proposed R11 "approval for any extension" does not provide a mechanism to appeal a denied extension. Additionally, Eversource notes that the proposed "approval for any extension" would come from the ERO while approval from a PC or RC would seem to be more appropriate as they are aware of local limitations which may be the basis for the needed extension.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

The SDT has met the directive in Order 851.

BPA understands that the SDT had to respond with proposed changes to meet the directive for R11. BPA would like to reiterate the industry's and NERC's opposition to developing corrective action plans for an extreme event (Supplemental GMD event) and the similarity to TPL-001-4. A GMD event is considered to be a one in one hundred year event. BPA believes that assessing the event and performing an evaluation of possible actions to reduce the likelihood of the impact is more appropriate than requiring a Supplemental GMD event corrective action plan.

BPA supports the comments made by NERC, referenced in FERC's Final Rule, issued on 11/15/18, Docket Nos. RM18-8-000 and RM15-11-003, Order No. 851; paragraph 35, lines

1-12, which were unfortunately rejected by FERC. Excerpted below:

NERC's comments reiterate the rationale in its petition that requiring mitigation "would result in the de facto replacement of the benchmark GMD event with the proposed supplemental GMD event." **39** NERC maintains that "while the supplemental GMD event is strongly supported by data and analysis in ways that mirror the benchmark GMD event, there are aspects of it that are less definitive than the benchmark GMD event and less appropriate as the basis of requiring Corrective Action Plans."**40** NERC also claims that the uncertainty of geographic size of the supplemental GMD event could not be addressed adequately by sensitivity analysis or through other methods because there are "inherent sources of modeling uncertainty (e.g., earth conductivity model, substation grounding grid resistance values, transformer thermal and magnetic response models) … [and] introducing additional variables for sensitivity analysis, such as the size of the localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments."**41**

39 *Id.* at 11-12; *see also id.* at 14 ("many entities would likely employ the most conservative approach for conducting supplemental GMD Vulnerability Assessments, which would be to apply extreme peak values uniformly over an entire planning area").

40 *Id.* at 13.

41 *Id.* at 15.

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

The proposed language meets the FERC directive.

Likes 0	
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Do you agree that R11 meets the directive? my possible answer is NO. **Please see EEI's comments**	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Yes, the proposed TPL-007-4 Requirement R11 meets the directive of FERC Order No. 851, Paragraph 39. Again, the FERC directive leaves little room for flexibility, requiring CAPs for the supplemental GMD event. While we are disappointed that FERC was not persuaded by the technical challenges of simulating locally-enhanced peak geoelectric field suitable for supplemental GMD event analysis, the Project 2019-01 SDT has met the intent.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees modifications to R11 meets the requirements in FERC Order 851. The modifications to R11 properly address Order 851's requirement to develop CAP to mitigate assessed supplemental GMD event vulnerabilities with provisions for extension of time on a case-by-case analysis.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Nick Batty - Keys Energy Services - NA - Not Applicable - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE's comments regarding Part 7.4 in question #1 as they also apply to Part 11.4.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	
Document Name	
Comment	

PSE will abstain from answering this question	
Likes 0	
Dislikes 0	
Response	

3. Do you agree that the Canadian variance is written in a way that accommodates the regulatory processes in Canada? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order while accommodating Canadian regulatory processes.

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	
Comment	
N/A	
Likes 1	Western Area Power Administration, 6, Jones Rosemary
Dislikes 0	
Response	

Bruce Reimer - Manitoba Hydro - 1

Answer	No
Document Name	
Comment	
The Canadian variance does not completely reflect the unique regulatory process in each region in Canada. The Manitoba Hydro Act prevents adoption of reliability standards that have the effect of requiring construction or enhancement of facilities in Manitoba. Manitoba Hydro modified the language of TPL-007-2 that works in Manitoba.	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	

Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees the Canadian variance portion of the standard is helpful for the utilities in the United States. However, SCL cannot comment on the language of the standard in the Canadian Variance portion where it relates to regulatory process in Canada.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP is not impacted by the Canadian variance..	
Likes 0	
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Not applicable	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
For the parts of the proposed changes to R7 (new R10) stated in the response to Question 1 that are accepted, Reclamation recommends conforming changes be made to the pertinent language in the Canadian variance.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Eversource has no opinion on the Canadian variance.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes

Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	
Comment	
The Canadian member of the SRC agrees that the Canadian variance is written in a way that accommodates the regulatory process in Canada.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 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 RSC no NGrid and NYISO	
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	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	
Document Name	
Comment	
Not applicable to FirstEnergy.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	
Document Name	
Comment	
CHPD defers the response to this question to the Canadian provinces to determine if the Canadian variance is written to accommodate the regulatory processes in Canada.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	

Answer	
Document Name	
Comment	
GTC's opinion is that this question should only be answered by Canadian entities.	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	
Document Name	
Comment	
PSE will abstain from answering this question	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No comment	
Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	
Document Name	

Comment	
GSOC's opinion is that this question should only be answered by Canadian entities.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See EEI’s comments” on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have comments on this question.
Likes 0
Dislikes 0
Response
David Jendras - Ameren - Ameren Services - 3
Answer
Document Name
Comment
Ameren agrees with and supports EEI comments.
Likes 0
Dislikes 0
Response
Bette White - AES - Indianapolis Power and Light Co. - 3
Answer
Document Name
Comment
IPI is not in the Canadian district
Likes 0
Dislikes 0
Response
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE
Answer
Document Name
Comment
N/A

Likes 0	
Dislikes 0	
Response	

4. Do you agree that the standard language changes in Requirement R7, R8, and R11 proposed by the SDT adequately address the directives in FERC Order No. 851? If you disagree please explain and provide alternative language and rationale for how it meets the directive of the order.

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 4 by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	No
Document Name	

Comment

As discussed in the response to Question 1, Exelon agrees that changes in Requirements R7, R8 and R11 meet the intent of the FERC directives, but without a clear CAP Extension Process the changes cannot be supported at this time.

On Behalf of Exelon: Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
See response to Q2 above.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the language in Requirements R7, R8 and R11 as proposed by the SDT believing that the changes conform to the directives contained in Order 851. Nevertheless, we cannot support these changes as sufficient or complete at this time until a CAP Extension Request Review Process is develop that ensure that key elements, as articulated in our response to Question 1, are addressed.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Please see comments submitted by EEI.	

Likes 0	
Dislikes 0	

Response

Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs

Answer	No
Document Name	

Comment

PSEG supports EEI's comments.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Reclamation recommends the language in Requirements R7 and R11 be combined into a single requirement addressing corrective action plans. Please refer to the proposed language provided in the responses to Questions 1 and 2.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI's comments.

Likes 0	
Dislikes 0	

Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD does not agree with the directives in FERC Order No. 851 for “Corrective Action Plan Deadline Extensions” or “Corrective Action Plan for Supplemental GMD Event Vulnerabilities” (see responses to questions 1 and 2). Therefore, CHPD does not agree the standard language changes in Requirement R7, R8, and R11 proposed by the SDT.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	
Comment	
The SRC agrees that the revisions to Requirements R7, R8, and R11 substantially satisfy FERC’s directives articulated in Order No. 851, and refers the SDT to the comments provided in response to Question Nos. 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
MISO supports the comments submitted by the IRC SRC.	
Likes 0	

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

The SDT has met the directive in Order 851.

BPA understands that the SDT had to respond with proposed changes to meet the directive. BPA believes requiring a corrective action plan for a Supplemental GMD Event is unreasonable and imposes an unnecessary burden on transmission owners and operators.

BPA believes that mitigation strategies for GMD events and the ensuing geomagnetically induced currents would likely be considered novel and in the Research and Development or prototype stages. As such, most devices or control/relay schemes that might be part of a corrective action plan could increase operational complexity and a potential loss of system security. While attempting to mitigate the risk from a low frequency benchmark GMD event, additional risk may be introduced which results in a net reduction in system security. Hence, there is caution from utilities and the industry in general about mandating corrective action plans for schemes and devices that are not well developed and commonly deployed.

BPA supports the comments made by NERC, referenced in FERC's Final Rule, issued on 11/15/18, Docket Nos. RM18-8-000 and RM15-11-003, Order No. 851; paragraph 35, lines

1-12, which were unfortunately rejected by FERC. Excerpted below:

NERC's comments reiterate the rationale in its petition that requiring mitigation

"would result in the de facto replacement of the benchmark GMD event with the

proposed supplemental GMD event." **39** NERC maintains that "while the supplemental

GMD event is strongly supported by data and analysis in ways that mirror the benchmark

GMD event, there are aspects of it that are less definitive than the benchmark GMD event

and less appropriate as the basis of requiring Corrective Action Plans."**40** NERC also

claims that the uncertainty of geographic size of the supplemental GMD event could not

be addressed adequately by sensitivity analysis or through other methods because there

are "inherent sources of modeling uncertainty (e.g., earth conductivity model, substation

grounding grid resistance values, transformer thermal and magnetic response models) …

[and] introducing additional variables for sensitivity analysis, such as the size of the

localized enhancement, may not improve the accuracy of GMD Vulnerability Assessments."**41**

39 *Id.* at 11-12; *see also id.* at 14 ("many entities would likely employ the most conservative approach for conducting supplemental GMD Vulnerability Assessments,

which would be to apply extreme peak values uniformly over an entire planning area”).

40 *Id.* at 13.

41 *Id.* at 15.

Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	

Response

Bruce Reimer - Manitoba Hydro - 1

Answer	Yes
Document Name	

Comment

The proposed language meets the FERC directive.

Likes 0	
Dislikes 0	

Response

Ayman Samaan - Edison International - Southern California Edison Company - 1

Answer	Yes
Document Name	

Comment

my possible answer is NO.

Please see EEI's comments

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	
Comment	

Yes, the proposed TPL-007-4 Requirements R7, R8, and R11 meets the directives of FERC Order No. 851.

However, FERC has not mandated the specific timetable proposed in Requirement R11, Part 11.3. Considering the 150% geoelectric field enhancement reflected by the supplemental GMD event over the benchmark GMD event, we suggest that the Project 2019-01 SDT modify Requirement R11, Parts 11.3.1 and 11.3.2 to three and six years, respectively.

Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	

SRP has no comments for the standard drafting team.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

None.

Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC

Answer	Yes
Document Name	
Comment	
SCL agrees modifications to R7, R8, and R11 properly address the requirements in FERC Order 851 as noted under 1 and 2 above.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Please see Texas RE’s answer to #1.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See EEI’s comments” on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	

5. Do you have any comments on the modified VRF/VSL for Requirements R7, R8, and R11?	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	No
Document Name	
Comment	
No comments on the modified VRF/VSL for Requirements R7, R8 and R11	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
No comment	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007

Answer	No
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

SCL agrees with the descriptions of VRF/VSL in the standard for requirements R7, R8, and R11.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Reclamation recommends combining R7 and R11. For consistency, Reclamation also recommends the VRF/VSL for these requirements be combined.	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
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's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the proposed Implementation Plan? If you think an alternate, shorter or longer implementation time period is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Continuing with a previous standard's implementation plan causes confusion, misunderstandings, and the increased potential for missed deadlines. Reclamation recommends retiring the implementation plans for previous versions of TPL-007 and creating a new implementation plan for TPL-007-4 so there is only one implementation plan to work toward.	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Bruce Reimer - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The implementation plan is likely long enough but does it make sense to have a standard in place that won't be effective for several years? Based on Canadian Law, when a standard is adopted it becomes immediately effective.	
Likes 0	

Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD does not agree with requiring a CAP for supplemental GMD event (TPL-007-4 R11). Therefore, CHPD does not agree with the implementation plan which requires compliance with R11.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comment	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

Yes, the proposed TPL-007-4 Implementation Plan is consistent; essentially no TPL-007-3 Compliance Dates are changed, except for the modified Requirements R7 and R11 (Requirement R8 proposed changes are trivial). Given the expectation of a rapid FERC approval process, the 01 January 2024 Compliance Dates to develop corrective actions for the supplemental GMD event are reasonable.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

SRP has no comments for the standard drafting team.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees with the impmentation plan for R7, R8, and R11. However, SCL would like to see a later effective date for R12 and R13 or clear guidelines on how to monitor and collect GIC from at least one GIC monitor located in the Planning Coordinator's area.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Travis Chrest - South Texas Electric Cooperative - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Frank Pace - Central Hudson Gas & Electric Corp. - 1,3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed that TPL-007-3 is incorrectly referenced on page 1 of the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	

Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	

7. The SDT proposes that the modifications in TPL-007-4 meet the FERC directives 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.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

TPL-007-4, in contrast to the majority of standards established by NERC, GMD Vulnerability Assessments are not representative of an existing utility practice. This is highlighted by the fact that there is a deficit of modeling tools available that would enable an entity to comply with the requirements specified herein. The burden of expenses relative to CAPs has yet to be established because there are very few examples of vulnerability assessments that have been completed for either the benchmark or the supplemental GMD events. In essence, the science to prudently study and assess system vulnerabilities related to a High Impact, Low Frequency (HILF) event on the system is not conclusive and still subjective. In short, the obligations have come before the development of proven modeling tools and mitigation techniques. Once again, AEP believes that R11 is unnecessarily duplicative of the obligations already required for the benchmark event, and as such, we do not believe it to be cost effective. Those resources would be better served for efforts having a discernable, positive impact on the reliability of the BES. Rather than pursuing this course, we believe a more prudent path, as well as a more cost effective path, would be as we propose in our response to Q1.

Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

No, we do not agree that the modifications in TPL-007-4 meet the FERC directives in a cost effective manner; the imposition of Requirement R11, Parts 11.3.1 and 11.3.2 deadlines for corrective action implementation are too short thereby escalating costs. We echo industry comments made during previous modifications to TPL-007-1: FERC opened the door for NERC to propose alternatives to the two- and four-year implementation of corrective actions (FERC Order No. 830, Paragraph 97); FERC was clearly persuaded by device manufacturers over the concerns of utility commenters that mitigation deadlines were impractical (FERC Order No. 830, Paragraph 102). This was particularly problematic because the hardware solutions that existed then, as well as today, remain widely unproven (only one implementation in the continental United States) and are simply not suitable for highly networked Systems (blocking GICs pushes the problem onto neighbors). Given that FERC has directed corrective actions and implementation deadlines, as well as facilitated time extensions, the cost-effectiveness of the proposed TPL-007-4 would be enhanced by including a section in the Technical Rationale that discusses how and when time extensions are reasonable. Examples could include a treatment of how to navigate the challenges of formulating appropriate joint-mitigations with neighbors to address widespread GMD impacts and how, during the process of mitigation implementation, unexpected System impacts may arise that delay completion.

Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
Requirements 7.3, 7.4, 11.3, and 11.4 should be revised to require extension request submittals be made to the entity's Reliability Coordinator (RC), not the ERO. The RC has the wide-area view, analysis tools, models and data necessary to ensure that extension requests are effectively evaluated. It is unlikely that the ERO will have the necessary information to assess the extension request, and the ERO and will seek RC concurrence in order to adequately respond to an extension request. This adds multiple steps and inefficiencies into the extension request process. The Requirements 7.3, 7.4, 11.3, and 11.4 should stipulate that extension requests are submitted to the RC for approval. This is a more appropriate and cost-effective approach to addressing the requests.	
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 industry is in the preliminary stages of assessing and developing mitigation measures for GMD events and has not had much time to develop engineering-judgement, experience, or expertise in this field. Revising the standard to include CAPs for the supplementary GMD event is not appropriate at this time as the industry is still building a foundation for this type of system event analysis and exploring mitigation measures. Without a sound foundation developed, requiring CAPs for the supplemental GMD event could lead to unnecessary mitigation measures and an immense amount of industry resources spent on a still developing science. CHPD suggests that the benchmark GMD event be fully vetted before moving onto additional scenarios such as the supplemental event.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	

Answer	No
Document Name	
Comment	

The proposed changes mandates implementation of a Corrective Action Plan for the supplemental GMD event (12 V/km). The research into this type of disturbance is still evolving. The available tools do not support studying this disturbance at this time. The tools available would allow for a uniform field over the entire planning Coordinator area. If this field is increased from 8 V/km to 12 V/km that corresponds to a disturbance well in excess of the 1/100 year level suggested by the benchmark. This is not just and reasonable. Let TPL-007-2 run through its first cycle of studies and review the assessment results. Perhaps the next cycle of studies could evolve to the proposed wording in TPL-007-4 once the research and tools have matured and an assessment of the potential costs have been tabulated to address the supplemental event.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

See EEI's comments.

Likes 0	
Dislikes 0	
Response	

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5

Answer	No
Document Name	
Comment	

It is difficult to assess the exact financial impacts of the requirements in this standard. The addition of CAP for Supplementary GMD event may or may not be cost effective.

Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA agrees that the SDT satisfied its obligation to modify TPL-007 to meet the directives in FERC Order No. 851. BPA can not determine if the directives are cost effective. The modifications are requiring a corrective action plan for an extreme event (Supplemental GMD event). The Transmission Planners and Transmission Owners have not done the analysis to determine the impact and the cost of the corrective action plans that would be required. BPA believes without this analysis, the cost effectiveness can not be determined. BPA believes that assessing the event and performing an evaluation of possible actions to reduce the likelihood of the impact is more appropriate than requiring a Supplemental GMD event corrective action plan.	
Likes 5	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 4, Martinsen John; Snohomish County PUD No. 1, 6, Liang John; Public Utility District No. 1 of Snohomish County, 1, Duong Long; Public Utility District No. 1 of Snohomish County, 5, Nietfeld Sam
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
We are concerned the cost and effort to address this standard could hinder other more important Transmission improvements.	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Comments: See comments on Question 2	
Likes 0	

Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

If unintended duplication of efforts between baseline and supplemental corrective action plans occurs, as referenced in the response to question 2, that would lead to unnecessary increases in costs to registered entities. Please reference the suggestion in our response to question 2.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

For the implementation of numerous, overlapping versions of the same standard (such as the implementation of TPL-007-2, TPL-007-3, and TPL-007-4) with lengthy phased-in implementation timelines, Reclamation supports the incorporation of insignificant subsequent modifications (such as the changes from TPL-007-2 to TPL-007-3 to TPL-007-4) in accordance with existing phased-in implementation milestones, but recommends that all previous implementation plans be retired so that there is only one implementation plan in effect at a time.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

The SPP Standards Review Group (SSRG) has no concerns to cost effective issues from a Planning Coordinator (PC) perspective, however, from the SPP membership perspective, the imposition of Requirement R11, Parts 11.3.1 and 11.3.2 deadlines for corrective action implementation are short, thereby escalating costs over two and four years. This timeframe could create issues for hardware solutions.

Given that FERC has directed corrective actions and implementation deadlines, as well as facilitated time extensions, the cost-effectiveness of the proposed TPL-007-4 would be enhanced by including a section in the Technical Rationale that discusses how and when time extensions are reasonable. Examples could include a treatment of how to navigate the challenges of formulating appropriate joint-mitigations with neighbors to address widespread GMD impacts and how, during the process of mitigation implementation, unexpected System impacts may arise that delay completion.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA supports comments submitted by AEP for Question #7	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no NGrid and NYISO	
Answer	No
Document Name	
Comment	
Requirements 7.3, 7.4, 11.3, and 11.4 should be revised to require extension request submittals be made to the entity's Planning Coordinator (PC), not the ERO. The PC has the wide-area view, analysis tools, models and data necessary to ensure that extension requests are effectively evaluated. It is unlikely that the ERO will have the necessary information to assess the extension request, and the ERO and will seek PC concurrence in order to adequately respond to an extension request. This adds multiple steps and inefficiencies into the extension request process. The Requirements 7.3, 7.4, 11.3, and 11.4 should stipulate that extension requests are submitted to the PC for approval. This is a more appropriate and cost-effective approach to addressing the requests.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	

Answer	No
Document Name	
Comment	
OPG concurs with the RSC comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SCL agrees; however, it is difficult to assess the true financial impacts of the requirements in this standard to SCL at this early stage. The modifications in the standard may or may not be cost-effective to SCL.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	

Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP has no comments for the standard drafting team.	
Likes 0	
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

NERC should evaluate the relative event probabilities with respect to the cost/benefit analysis of GMD event mitigations. Planning for increasingly rare system events is inherently at odds with economic planning and rate payer responsibilities.

Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE VOTER	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Frank Pace - Central Hudson Gas & Electric Corp. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Travis Chrest - South Texas Electric Cooperative - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Arnold - City of Independence, Power and Light Department - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott McGough - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrea Barclay - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen	
Answer	
Document Name	
Comment	
More experience with implementing the standard is required in order to better understand the implications on its cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	

8. Provide any additional comments for the standard drafting team to consider, if desired.

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG concurs with the RSC comment	
Likes 0	
Dislikes 0	
Response	
Rahn Petersen - PNM Resources - Public Service Company of New Mexico - 1 - WECC,Texas RE	
Answer	
Document Name	
Comment	
Nothing further	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2019-01 Modifications to TPL-007	
Answer	
Document Name	
Comment	

In Requirements R7 and R11, the SRC suggests replacing “their” with “its” just prior to the first mention of “System” for grammatical reasons.

Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	
Document Name	
Comment	

MISO supports the comments submitted by the IRC SRC. In addition, MISO would like to propose a clarification to requirement R6, part 6.4.

As written, the Transmission Owner and Generator Owner functions referenced under TPL-007-4, requirement R6, Part 6.4 are not functions that are included in the identification of the individual and joint responsibilities under TPL-007-4, requirement R1. As a result, when the Planning Coordinator, in conjunction with its Transmission Planner(s) identifies the individual and joint responsibilities, the Transmission Owner and Generator Owner are not party to this information and so would not know who to provide the results to.

In addition, there is no provision under R1 that requires the Planning Coordinator to determine or communicate who applicable Transmission Owners (section 4.1.3) and Generator Owners (section 4.1.4) within its area should send the results of their benchmark thermal impact assessment to.

MISO became aware of this gap following an inquiry from a transformer owner when they did not know where to send the results.

Possible remedies:

1) Modify Requirement R6, Part 6.4 to reference Requirement 5, i.e. “Be performed and provided to the responsible entity(ies) ***that provided the GIC flow information in accordance with Requirement 5***, within 24…

2) Clarify the scope of requirement Require R1 to specify that the Planning Coordinator in conjunction with its Transmission Planner(s) determine which responsible entity(ies) applicable Transmission Owner(s) and Generator Owner(s) in their area should send the results of their benchmark thermal impact assessment(s) to.

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	

Answer	
Document Name	

Comment

Ameren agrees with and supports EEI 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 RSC no NGrid and NYISO

Answer	
Document Name	

Comment

The Implementation Guidance document, as written, is not acceptable. Boundaries cannot be established with a CMEP Implementation Guidance document. CMEP Implementation Guidance is a means to identify one approach to being compliant while not precluding the use of other approaches. Auditors audit to requirements and don't use CMEP Implementation Guidance to establish requirements which go beyond the standard's requirements. Problematic statements appearing in Chapter 8 of the document include, but may not be limited to, the following:

• "The local geoelectric field enhancement should not be smaller than 100 km.."- this threshold value of 100 km does not appear in the standard requirement

• "…at a minimum, a West-East orientation should be considered when applying the supplemental event"- the standard requirement does not contain any wording of a minimum consideration

• "Geoelectric field outside the local enhancement:

a. Amplitude: should not be smaller than 1.2 V/km…" This also does not appear in the standard.

• "The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event". This statement creates boundaries outside of requirements, which guidance cannot do

The use of "shall" or "must" should not be used unless they are being used in the requriements in the standard. This is particularly true for the requirement associated with sensitive/confidential information. It is not in the standard and was added in the IG as an additional "requirement".

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	
Document Name	

Comment

Westar Energy and Kansas City Power & Light Company incorporate by reference and support comments submitted in response to Question 8 by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends that TPL-007-4 be consistent with other standards that require data to be submitted from the applicable entities to the Regional Entity. Reliability Standards FAC-003-4, EOP-008-2 Requirement R8, and PRC-002-2 Requirement R12 explicitly state the data shall be submitted to the Regional Entity in the requirement language or in Part C. Compliance section of the standard. There is no need for an extraneous process document describing where to submit the information.

Texas RE is concerned with introducing a separate process document for submitting CAP extension requests for the following reasons: the document would not be FERC approved, how would entities and regions know that it exists, where would it be housed, etc. Registered entities should not have to look beyond the standard in order to understand how to comply with a requirement.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

- R7.1 (page 6 of TPL-007-4 clean draft):
    - The portion of this sub-requirement starting from “Examples include:” should be moved to the Implementation Guidance, as the bullet point list’s purpose is more in line with the stated purpose of the Guidance. Consider updating R11.1 as well.
    - To this end, Page iii of Implementation Guidance Document needs to be updated to reflect new SERC region.
- Consider deleting the four references to Attachment 1 in the Draft Technical Rationale document (Draft Tech Rationale_TPL-007-4.pdf).

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 6, Group Name Entergy

Answer	
Document Name	

Comment

Entergy supports comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

EEI acknowledges and supports the good work by the SDT in support of this Reliability Standard believing that it conforms to the directives issued in FERC Order 851. We also recognize that the supporting/companion ERO process document simply represents an initial draft of the Extension Request Process. Nevertheless, the process of CAP extention reviews and approvals are inextricably tied to the modification of this standard. For this reason and as stated in more detail in our response to Question 1, this companion process document needs to include additional details to ensure effective and transparent processing of entity CAP Extension Requests. The process should also be formally codified in parallel with the required revisions to this Reliability Standard.

Likes 0	
Dislikes 0	

Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
Please see comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Sean Cavote - PSEG - 1,3,5,6 - NPCC,RF, Group Name PSEG REs	
Answer	
Document Name	
Comment	
PSEG supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	
Document Name	
Comment	
With the change that the Benchmark and Supplimental analysis both require a CAP, shouldn't they be consolidated into a single study effort to reduce the overall number of requirements? The Supplimental seems to only be a Benchmark with additional areas of increased field strength, unless I am missing some nuiance in how they are performed?	

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
"See EEI's comments" on Modifications to TPL-007-3 – TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	
Document Name	
Comment	
What was the rationale behind removing the Supplemental Material? It provided some background information and sources that could be useful for understanding the practicality of the requirement.	
Likes 0	

Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

Comments:

1. The language in Requirement 7.4 doesn't properly align with the FERC Directive on who should be approving the extensions. The FERC directive doesn't clearly state that the ERO should be the entity approving the extension. We recommend the drafting team consider revising their proposed language to include "ERO, or its delegated designee." This modification will allow regional entities or other designees to better adjudicate CAP time extensions given their close proximity, System expertise, and existing compliance program obligations.

2. The proposed language in Requirement R11 Part 11.3 doesn't align with the FERC directive in reference to the duration of the Implementation of the CAP. The FERC directive doesn't clarify a specific time frame pertaining to the Implementation of the CAPs. Recommend the drafting team consider revising their proposed language for Requirement R11.3 Parts 11.3.1 and 11.3.2 to include an implementation timeframe of three (3) and six (6) years respectively.

3. The SSRG recommends that the drafting team considers including more technical language in the Technical Rationale document, explaining how/why the drafting team came to their conclusions to revising these particular requirements. The document doesn't provide technical reasoning the drafting team developed or revised this requirement. Chapters 7, 8, and 11 are general, and have no technical information explaining the drafting team's actions.

4. The SSRG recommends the drafting team consider implementing all the redlines changes to the RSAW that have been identified in the other documents to promote consistency throughout their documentation process.

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

ReliabilityFirst has identified a change in Requirement R1 that was not captured in the redline. When Requirement R1 was copied over to TPL-007-4, the SDT dropped the word "area" from the requirement. As is, the Requirement does not seem to make sence. Please note (in bold text) the updated requirement below:

Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning ***area*** *for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.*

Likes 0	
Dislikes 0	

Response

Andrea Barclay - Georgia System Operations Corporation - 3,4

Answer	
Document Name	

Comment

The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Thank you for the opportunity to comment. ACES appreciates the efforts of drafting team members and NERC staff in continuing to enhance the standards for the benefit of reliability of the BES.

Likes 0	
Dislikes 0	

Response

Scott McGough - Georgia System Operations Corporation - 3,4

Answer	

Document Name	
Comment	

The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.

Likes 0	
Dislikes 0	
Response	

Keith Jonassen - Keith Jonassen On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Keith Jonassen

Answer	
Document Name	
Comment	

ISO-NE believes that the additional guidance provided in chapter 8 of the draft Transmission System Planned Performance for Geomagnetic Disturbance Events Implementation guidance document for simulating the supplemental GMD event is very helpful. ISO recommends reviewing the language in that chapter to ensure consistency with the purpose of the implementation guidance document as explained in the first paragraph of its Introduction section (i.e. make clear that the information provided describes an example of how the standard's requirements could be met), and not infer the introduction of additional requirements which would not otherwise be contained in the TPL-007 standard.

Likes 0	
Dislikes 0	
Response	

Deanna Carlson - Cowlitz County PUD - 5

Answer	
Document Name	
Comment	

The addition of the ERO for approving any timeline extension may prove to be excessive and burdensome for NERC, and possibly the responsible entity as well. The District recommends an additional statement where the ERO has 60 days to provide notice to the responsible entity when a CAP submittal with an extension request will require ERO approval following full review. Otherwise, if NERC acknowledges receipt with no further notice to the responsible entity, the CAP and extension request is automatically approved. This would reduce the work load on NERC to regarding CAPs with extension requests that are minimal or otherwise considered low risk to the BES.

Additionally, there is no consideration of cost. It is possible that a CAP could be expensive and difficult to develop a four-year plan without hindering other more important Transmission Planning objectives in compliance to TPL-001.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Steven Dowell - Alcoa - Alcoa, Inc. - 7	
Answer	
Document Name	
Comment	
Alcoa would like to abstain. Alcoa would urge the SDT to examine cost/benefit analysis for implementation of GMDs at non-critical facilities.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	

The only difference between R.4 through R.7 and R.8 through R.11 is the threshold for the maximum effective GIC value (75 A for the Benchmark GMD Event, and 85 A for the Supplemental GMD event). Based on this fact, the number of requirements in the standard could be reduced, if R.4 through R.7 and R.8 through R.11 were combined.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI's comments.	
Likes 0	
Dislikes 0	
Response	

James Mearns - Pacific Gas and Electric Company - 1,3,5	
Answer	
Document Name	
Comment	
As inverter based sources of generation increase on the grid, the requirements of IEEE-Std-519 related to THD percentages (to the 40th harmonic) may need to be revisited. Energy at higher order harmonic frequencies has been observed at bulk (>20 MW) solar sites, which may increase potential for thermal saturation in banks that would otherwise not be susceptable to GIC. Although separate from the specific guidance in this TPL, this may represent a sensitivity factor that could be weighted as part of the overall security assessment of the banks being reviewed.	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	

Comment	
The Implementation Guidance document, as written, is not acceptable. Boundaries cannot be established with a CMEP Implementation Guidance document. CMEP Implementation Guidance is a means to identify one approach to being compliant while not precluding the use of other approaches. Auditors audit to requirements and don't use CMEP Implementation Guidance to establish requirements which go beyond the standard's requirements. Problematic statements appearing in Chapter 8 of the document include, but may not be limited to, the following: • "The local geoelectric field enhancement should not be smaller than 100 km.."- this threshold value of 100 km does not appear in the standard requirement • "…at a minimum, a West-East orientation should be considered when applying the supplemental event"- the standard requirement does not contain any wording of a minimum consideration • "Geoelectric field outside the local enhancement: a. Amplitude: should not be smaller than 1.2 V/km…" This also does not appear in the standard. • "The schematic in Figure 1 illustrates the boundaries to apply the supplemental GMD event". This statement creates boundaries outside of requirements, which guidance cannot do. The use of "shall" or "must" should not be used unless they are being used in the requriements in the standard. This is particularly true for the requirement associated with sensitive/confidential information. It is not in the standard and was added in the IG as an additional "requirement".	
Likes 0	
Dislikes 0	
Response	
Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 1, 3; Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Louis Guidry	
Answer	
Document Name	
Comment	
Cleco does agree with the concept, the language, particularly with regard to the extent of the Corrective Action Plan (R11) and various timetable requirements are overreaching and place undue burden on potentially affected entities.	
Likes 0	
Dislikes 0	
Response	
Ayman Samaan - Edison International - Southern California Edison Company - 1	
Answer	

Document Name	
Comment	
Please see EEI's comments	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
We don't need to remind the Project 2019-01 SDT that this will be the fourth version of the TPL-007 Reliability Standard in three years. The team has done a fine job of meeting the directives of FERC Order No. 851, but we encourage the SDT to push back harder on the corrective action implementation timeframes for the supplemental GMD event. From a holistic view, this effort to address vulnerability to GMD events appears to be getting too far ahead of good, robust science and engineering. The industry simply does not have mature hardware solutions available to potentially mitigate GIC issues, anticipated from mathematical model simulation software packages that are updating at least as frequently as the TPL-007 standard itself has changed, while constantly chasing the emerging GMD science. The reliability of the BES is, and will be, best served by the improved awareness of GMD impacts embodied by the TPL-007, as well as operator responsiveness required by EOP-010-1. The existing required identification of corrective actions is key; just give industry the time and flexibility to adopt solutions that suit them best.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP thanks the standards drafting team for their efforts on this project.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - SERC	
Answer	
Document Name	
Comment	
The Standard Draft Team (SDT) has added language to submit requests for extensions of timeframes to the ERO, i.e., NERC, for approval. Seminole reasons that individual entities should communicate such requests to the RRO, e.g., SERC, WECC, etc., and that the individual RRO should approve/deny such requests instead of NERC. Seminole is requesting the language be revised to capture this.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - SERC	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
As previously stated, many of the obligations within TPL-007, both existing and proposed, precede industries' full understanding of GMD and its true, discernable impacts. This proves challenging when attempting to develop standards to adequately address the perceived risks. We support, and are appreciative of, the efforts of the standards drafting team and their desire to address the directives issued in Order No. 851, however we believe the spirit of those directives can be met without pursuing a path that duplicates obligations already required for the benchmark event. We believe a more prudent path for meeting the directive would be for the SDT to work with industry and determine an agreeable reference peak geoelectric field amplitude (one not determined solely by non-spatially averaged data) for a single GMD Vulnerability Assessment (benchmark) that potentially requires a Corrective Action Plan. This would serve to both achieve the spirit of the directive, as well as avoid unnecessary duplication of efforts that provide no added benefit to the reliability of the BES. Due to the concerns we have expressed above, AEP has chosen to vote negative on the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	