Comment Report

Project Name:	2013-03 Geomagnetic Disturbance Mitigation | TPL-007-2
Comment Period Start Date:	6/28/2017
Comment Period End Date:	8/11/2017
Associated Ballots:	2013-03 Geomagnetic Disturbance Mitigation TPL-007-2 IN 1 NB 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2 IN 1 ST

There were 58 sets of responses, including comments from approximately 147 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT developed proposed Requirements R8 – R10 and the supplemental GMD event to address FERC concerns with the benchmark GMD event used in GMD Vulnerability Assessments. (Order No. 830 P.44, P.47-49, P.65). The requirements will obligate responsible entities to perform a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for potential impacts of localized peak geoelectric fields. Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

2. The SDT developed the *Supplemental GMD Event Description* white paper to provide technical justification for the supplemental GMD event. The purpose of the supplemental GMD event description is to provide a defined event for assessing system performance for a GMD event which includes a local enhancement of the geomagnetic field. Do you agree with the proposed supplemental GMD event and the description in the white paper? If you do not agree, or if you agree but have comments or suggestions for the supplemental GMD event and the description in the white paper provide your recommendation and explanation.

3. The SDT established an 85 A per phase screening criterion for determining which power transformers are required to be assessed for thermal impacts from a supplemental GMD event in Requirement R10. Justification for this threshold is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment* white paper. Do you agree with the proposed 85 A per phase screening criterion and the technical justification for this criterion that has been added to the white paper? If you do not agree, or if you agree but have comments or suggestions for the screening criterion and revisions to the white paper provide your recommendation and explanation.

4. The SDT revised the *Transformer Thermal Impact Assessment* white paper to include the supplemental GMD event. Do you agree with the revisions to the white paper? If you do not agree, or if you agree but have comments or suggestions on the revisions to the white paper provide your recommendation and explanation.

5. The SDT developed proposed Requirement R7 to address FERC directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments (P. 101, 102). Do you agree with the proposed requirement? If you do not agree, or if you agree but have comments or suggestions for the proposed requirement provide your recommendation and explanation.

6. The SDT developed Requirements R11 and R12 to address FERC directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data (P. 88; P. 90-92). Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

7. Do you agree with the proposed Implementation Plan for TPL-007-2? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

8. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in proposed TPL-007-2? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs provide your recommendation and explanation.

9. The SDT believes proposed TPL-007-2 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for

improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

10. Provide any additional comments for the SDT 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
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF

					Ginger Mercier	Prairie Power, Inc.	1	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Mark Ringhausen	Old Dominion Electric Cooperative	4	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Ryan Strom	Buckeye Power, Inc.	4	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
Colby Bellville	Colby Bellville		FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO

					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Electric Reliability Council of Texas, Inc.	Elizabeth Axson	2		IRC Standards Review Committee	Elizabeth Axson	ERCOT	2	Texas RE
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Greg Campoli	NYISO	2	NPCC
					Terry BIlke	Midcontinent ISO, Inc.	2	MRO
					Ali Miremadi	California ISO	2	WECC
					Matthew Goldberg	ISO NE	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SPP RE
Lower Colorado River Authority	Michael Shaw	6		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Alabama Power Company	3	SERC

					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Hydro One, HQ and IESO	Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC

					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Amy Casuscelli	Xcel Energy	1,3,5,6	SPP RE
					Louis Guidry	Cleco	1,3,5,6	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Jamison Cawley	Nebraska Public Power District	1	SPP RE
					Scott Jordan	Southwest Power Pool	2	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Jonathan Hayes	Southwest Power Pool	2	SPP RE
					Allan George	Sunflower Electric Power Corporation	1	SPP RE
Santee Cooper	Shawn Abrams	1		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Chris Wagner	Santee Cooper	1	SERC

1. The SDT developed proposed Requirements R8 – R10 and the supplemental GMD event to address FERC concerns with the benchmark GMD event used in GMD Vulnerability Assessments. (Order No. 830 P.44, P.47-49, P.65). The requirements will obligate responsible entities to perform a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for potential impacts of localized peak geoelectric fields. Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP is concerned by the potential duplication of efforts for any assets that are brought into scope by both the Benchmark and Supplemental Vulnerability Assessments (R6 and R10). While it may not be the drafting team's intent that multiple thermal impact assessments be conducted for the same assets, nor that two sets of suggested actions be developed to mitigate the impact of any GICs, the current draft does not make this explicitly clear. AEP requests that additional clarity be added so that duplicative efforts would not be necessary for any assets that are brought into scope under both the Benchmark and Supplemental Vulnerability Assessments. In general, the SDT should look for opportunities to minimize the potential duplication of work and evidence requirements throughout the drafted standard.

Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	

It is not clear how complying with Requirements R8 to R10 will mitigate GMD risk to BES reliability. This proposal does not address the FERC concerns of developing a GMD benchmark not solely based on a spatially averaged magnetometer data. Manitoba Hydro (MH) believes that specifying a one methodology in the standard is not appropriate because of the diversity of the BES across the continent and different level of risk tolerances among the responsible entities. Instead of asking to follow a specific GMD Vulnerability Assessment methodology, MH would like to propose the SDT to consider providing an option in the standard where the responsible entities can develop their own GMD Assessment Methodology based on the technical knowledge obtained through the research work performed on GMD Vulnerability Assessments in their system.

In Manitoba, for example, NRCAN has calculated the 1/100 year geoelectric field to be roughly 5 V/km at the northernmost magnetometer site in Manitoba (Churchill) using specific model of the earth resistivity in Manitoba. NRCAN has done similar calculations for Alberta and has also found the field to be much lower than 8 V/km as well. Rather than spatial averaging, NRCAN used extreme value mathematics to calculate the fields.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	

Comment
AZPS agrees with the requirements as written, but has concerns regarding the inconsistent treatment of deadline or time-related requirements or sub-requirements in the Table of Compliance Elements. More specifically, both Requirement R8 and R9 contain 90 day deadlines for administrative activities. However, these requirements/sub-requirements are treated differently with respect to the violation severity levels (VSLs). In particular, Requirement R8 treats the failure to timely provide/respond within 90 days as one element and does not increase the VSL based on the duration of the delay beyond the 90 day time period. Conversely, Requirement R9 ties the VSL directly to the duration of the delay beyond the 90 day time period. AZPS notes that the activities associated with the 90 day time periods are administrative in nature, e.g., providing a report or a response, and, therefore, will have a minimal (if any) impact on the reliability of the Bulk Electric System (BES). For this reason, AZPS recommends that the SDT conform Requirement R9 to the form provided in Requirement R8. Such revision will provide consistency and more accurately reflect the actual or potential impact on the BES.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC	
Answer	No
Document Name	

Comment
Hydro-Quebec considers that because of the specificity of its network, (on a wide area, with long transmission lines and northern location) the benchmark event is sufficiently severe and covers the possible impact of the localized enhancement on our grid. These requirements burden the responsible entities to perform additional assessments that are both costly and uneffective. Based on prior real measurements done on geomagnetic local disturbances in Abitibi (see reference below), we think that it would be preferable to wait for further analysis that takes into account real electric fields and current measures and not only magnetic measurements and calculated electric fields. Therefore adding a supplemental event on the already severe and pessimistic benchmark event should wait. Hydro Québec is currently in discussion with Natural Ressources Canada to complete an analysis using Canadian magnetometer data in the province of Québec. Hydro-Quebec acknowledges that the requirements address the FERC concerns. Reference: *A study of geoelectromagnetic disturbances in Quebec*. (IEEE Transactions on Power Delivery in 1998 and in 2000)

Likes 0	
Dislikes 0	

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

Hydro-Quebec considers that because of the specificity of its network, (on a wide area, with long transmission lines and northern location) the benchmark event is sufficiently severe and covers the possible impact of the localized enhancement on our grid. These requirements burden the responsible entities to perform additional assessments that are both Costly and uneffective.

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Hydro-Quebec acknowledges that the requirements address the FERC concerns.

Reference: *A study of geoelectromagnetic disturbances in Quebec*. (IEEE Transactions on Power Delivery in 1998 and in 2000)

Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	

The intent of requirements R8 to R10 is not clear. It is understood that the intent is to address the directive in FERC Order No 830; however, it is not clear how complying with requirements 8-10 will mitigate GMD imposed risk to BES reliability.

Requirement R4 requires responsible entities to perform Benchmark GMD Vulnerability Assessments (based on a benchmark GMD event) to identify risk to BES reliability. Requirement R7 requires responsible entities to mitigate the identified risk by developing a corrective action plan.

The new requirements R8 to R10 are asking for additional assessments and evaluations to identify risk to BES reliability. The additional assessments required in R8 is arguably repeating what is required in R4 based on an amplified GMD event called supplemental GMD benchmark event.

It is arguable that performing the GMD vulnerability assessments based on the supplemental GMD benchmark event will result in identification of a higher risk to BES reliability in comparison with risk identified by performing GMD assessments using the GMD benchmark event currently in TPL-007-1.

Based on the current wording of the standard, the responsible entity is not required to consider the elevated risk (based on the supplemental GMD assessments) in their corrective action plans. Requirement 8.3 states:

"If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted."

The word "evaluation" suggests further assessments but not necessarily any further mitigations of risk. So the real question is why would responsible entities be required to perform a supplemental assessment? And how is this additional assessment designed to mitigate risk to BES reliability?

The Standard Drafting Team has not revised the GMD benchmark event definition rather they introduced a new supplemental GMD event to account for potential impacts of localized peak geoelectric filed.

In paragraph 44, FERC Order No. 830 directed NERC to revise the GMD benchmark event definition so that the reference peak geoelectric field amplitude component is not solely based on spatially-averaged data. This approach will burden the responsible entities to perform additional assessments without a clear outcome.

We recommend that the Standard Drafting Team follow the results based standard development concept. The requirements should be focused on required actions or results (the "what") and not necessarily the methods by which to accomplish those actions or results (the "how").

Paragraph 65 in FERC Order No. 830 suggests that NERC could propose "some equally efficient and effective alternative". An alternative approach is to move away from specifying a methodology as the only option to perform GMD assessments in the standard. Instead, create an option for the entities to develop their own GMD assessment methodology based on their own research of GMD risks to and impact on BES reliability.

Responsible entities across the continent have diverse systems, equipment, resources, and risk tolerance. Specifying a one approach fits-all does not seem to be appropriate.

The benchmark GMD event and the supplemental GMD event described in the whitepapers (and currently referenced within the standard requirements) can each be used to perform GMD assessments; however, the standard should not limit the entities to only use these prescribed GMD events. Instead, the standard should allow entities to perform GMD assessments based on alternative GMD events as justified by the responsible entities based on their own research and methodology.

Ultimately, whichever GMD assessment methodology the responsible entity chooses to use, the system-wide impact and transformer thermal impact should be assessed.

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response

Joel Robles - Omaha Public Power District - 1,3,5,6

Answer	No
Document Name	

Comment

. OPPD will be supporting MRO NSRF comments. Please note this on your ballot when you vote.

Likes 0	
Dislikes 0	

Response

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG agrees that proposed Requirements R8 – R10 and the supplemental GMD event **attempts** to address FERC concerns with the benchmark GMD event used in GMD Vulnerability Assessments, however they fell short of mitigating GMD risk to the reliability of BES.

Requirement R10 – "**10.3.** Describe **suggested actions** and supporting analysis to mitigate the impact of GICs, if any; .." is just a good intention and cannot account for a Corrective Action Plan.

Moreover we now have two type of GMD events the Benchmark and the Supplemental; OPG is of the opinion that they should be amalgamated in one GMD type of events (albeit this may require GMD benchmark event definition revision). OPG believes that Supplemental GMD event assessment will render the Benchmark GMD event assessment obsolete (based on the more stringent condition) and thus will be an unnecessary budgetary burden. Only Requirement R4 based on the benchmark GMD event VA is leading to a CAP via R7, and this does not happen for the Supplemental GMD event VA based on the new R8 – R10	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
NCPA disagrees with having to perform supplemental GMD assessments. If it is to be required, then there should be a TRF MVA threshold of 500 MVA or greater. NCPA also disagrees with having to provide any assessment to any registered entity, other than our TP or RC.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
NCPA disagrees with having to perform supplemental GMD assessments. If it is to be required, then there should be a TRF MVA threshold of 500 MVA or greater. NCPA also disagrees with having to provide any assessment to any registered entity, other than our TP or RC.	
Likes 0	
Dislikes 0	
Response	
William Harris - Foundation for Resilient Societies - 8	
Answer	No
Document Name	Foundation for Resilient Societies on NERC Project 2013 081117_Submitted.docx

Comment
Resilient Societies has concerns that the relevant classes of GMD events are not fully addressed; that the 75 amps per phase threshhold is imprudent and not science based, and that a complementary effort is needed to test equipment under load and to test long replacement time equipment types to destruction. See attacheed Comments.

Likes 0	
Dislikes 0	

Response

Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	

Comment
This will place considerably more of a burden on the entities performing the GMD Vulnerability Assessments with the need to perform another whole assessment, but also, presumably, with the need to collect the data needed for creation of a "localized peak geoelectric field".

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	

Comment
NIPSCO agrees that supplemental GMD vulnerability assessment accounts for potential impact of localized peak geo-electric fields. However, instead of its own set of requirements, we feel it is appropriate to consider the supplemental GMD vulnerability assessment as a sensitivity case to the benchmark GMD vulnerability assessment. In addition, Requirement R8 requires conducting analysis for any potential cascading due to supplemental GMD event. However, R4 (Benchmark GMD vulnerability assessment) does not require such potential cascading evaluation. A uniformity in requirement would be desirable.

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1

Answer	Yes
Document Name	
Comment	
The supplemental GMD vulnerability assessment does not appear to be an overly onerous burden on the responsible entities as it is an enhancement based on the already required benchmark assessment. The potential impacts of localized peaks are necessary to evaluate due to the short time constant of the windings and structures affected by stray fields resulting from part cycle saturation.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
For R8.4 and R9 and their associated measures, BPA proposes rather than “shall be provided/shall provide” that the wording be changed to “shall make available.” For the western interconnection, a separate entity may be collecting interconnection-wide data.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
The ability to perform a system-wide study at the supplemental GMD level is helpful in cases where software cannot support a localized event. It is not overly clear why 85 A is acceptable for the supplemental assessment vs. 75 A for the benchmark assessment. The distinction between the two should be made clearer (e.g. “85 A is acceptable even as a higher value because the local (higher magnitude) field is assumed to be applied for a shorter duration”)	
Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	

Comment
TPLTF Discussion: The group agrees with the SDT approach to addressing FERC Order No. 830 Paragraph 44. In effect, the SDT has specified an extreme value for geoelectric field, called the supplemental GMD event, intended to represent a locally-enhanced geoelectric field experienced by a limited geographic area. In other words, the SDT has proposed a means by which Planning Coordinators and Transmission Planners can approximate a non-geospatially-averaged peak geoelectric field, thus meeting the intent of the FERC Order No. 830 directive. While determining peak geoelectric field amplitudes not based solely on spatially-averaged data is a significant challenge to meeting the FERC directive, primarily because of the lack of North American data, as well as analytical tools available to Planning Coordinators and Transmission Planners, the group believes the SDT has found a workable approach. The group would like to note that it will be non-trivial to apply the localized peak geoelectric field in the supplemental GMD event to a spatially-limited area, described in the proposed TPL-007-2 Attachment 1, given available software tools and available personnel resources. This will be especially pronounced for Planning Coordinators and Transmission Planners with large geographical footprints. Many planning entities will be forced to apply the supplemental peak geoelectric field over their entire area, in effect simply studying a higher magnitude benchmark GMD event. While the group believes this is prominently conservative, as stated above, we understand and support the SDT approach to this directive. It is likewise noted that the definition of a spatially-limited area is absent in the materials published by the SDT, but this vagary supports better analytical flexibility for Planning Coordinators and Transmission Planners and should not be defined in the draft standard.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment
SRP supports the response provided by WAPA on behalf of TPLTF for question 1

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) commends the efforts of the SDT and believes Requirements R8 – R10 address FERC concerns with the benchmark GMD event used in GMD Vulnerability Assessments. Additionally, CenterPoint Energy agrees that the supplemental GMD Vulnerability Assessment accounts for potential impact of localized peak geo-electric fields”.

CenterPoint Energy shares AEP’s concern with the potential duplication of efforts for any assets that are brought into scope by both the Benchmark and Supplemental Vulnerability Assessments (R6 and R10). While it may not be the drafting team’s intent that multiple thermal impact assessments be conducted for the same assets, nor that two sets of suggested actions be developed to mitigate the impact of any GICs, the current draft does not make this explicitly clear. CenterPoint Energy supports AEP’s request that additional clarity be added so that duplicative efforts would not be necessary for any assets that are brought into scope under both the Benchmark and Supplemental Vulnerability Assessments.

Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	

While disagreeing with the original FERC determination requiring the modification to the benchmark GMD event so that the assessments are not based solely on spatially-averaged data using the determined reference 8 V/km peak geoelectric field amplitude, we do agree on the SDT’s proposal of conducting a supplemental assessment using 12 V/km as the reference non-spatially averaged peak geoelectric field amplitude (as opposed to using the alternative 20 V/km non-spatially averaged peak value noted by FERC in the GMD Interim Report which would have overestimated the severity of a 1-in-100 year GMD event).

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

The SPP Standards Review Group agrees with the SDT approach to addressing FERC Order No. 830 Paragraph 44. In effect, the SDT has specified an extreme value for geoelectric field, called the supplemental GMD event, intended to represent a locally-enhanced geoelectric field experienced by a limited geographic area. In other words, the SDT has proposed a means by which Planning Coordinators and Transmission Planners can approximate a non-geospatially-averaged peak geoelectric field, thus meeting the intent of the FERC Order No. 830 directive. While determining peak geoelectric field amplitudes not based solely on spatially-averaged data is a significant challenge to meeting the FERC directive, primarily because of the lack of North American data, as well as analytical tools available to Planning Coordinators and Transmission Planners, the group believes the SDT has found a workable approach.

The group would like to note that it will be non-trivial to apply the localized peak geoelectric field in the supplemental GMD event to a spatially-limited area, described in the proposed TPL-007-2
Attachment 1, given available software tools and available personnel resources. This will be especially pronounced for Planning Coordinators and Transmission Planners with large geographical footprints. Many planning entities will be forced to apply the supplemental peak geoelectric field over their entire area, in effect simply studying a higher magnitude benchmark GMD event. While the group believes this is prominently conservative, as stated above, we understand and support the SDT approach to this directive. It is likewise noted that the definition of a spatially-limited area is absent in the materials published by the SDT, but this vagary supports better analytical flexibility for Planning Coordinators and Transmission Planners and should not be defined in the draft standard.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	Yes
Document Name	

Comment

See comment to Q 3.

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Huitt - Xcel Energy, Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Eason - Joshua Eason On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Joshua Eason	
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	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Colby Bellville On Behalf of: Dale Goodwine, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
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	
Quintin Lee - Eversource Energy - 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 Hydro One, HQ and IESO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Buyce - City Utilities of Springfield, Missouri - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	

Please see comments of Joesph N. O'Brien.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.

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	
Thomas Rafferty - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

2. The SDT developed the *Supplemental GMD Event Description* white paper to provide technical justification for the supplemental GMD event. The purpose of the supplemental GMD event description is to provide a defined event for assessing system performance for a GMD event which includes a local enhancement of the geomagnetic field. Do you agree with the proposed supplemental GMD event and the description in the white paper? If you do not agree, or if you agree but have comments or suggestions for the supplemental GMD event and the description in the white paper provide your recommendation and explanation.

William Harris - Foundation for Resilient Societies - 8	
Answer	No
Document Name	
Comment	
This is duplicative, but worse, both threshholds are likely to be above actual thresholds at which transformers catch fire, epxlode, or both.	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Increased costs do not justify the low, if any, reliability benefits.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Increased costs do not justify the low, if any, reliability benefits.	
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	

1. Paragraph 2, page 12 of the Supplemental GMD Event Description White Paper – the Drafting Team briefly discusses that the geographic area of the local enhancement is on the order of 100 km in N-S (latitude) and on the order of 500 km E-W (longitude). We recommend the SDT to provide additional information on the selection of 'on the order of 500 km' for longitudinal width. It is not clear why and how a width of 500 km(s) was selected. Why **not** consider a **longitudinal width** on the order of 100 km?
2. Figure II-1, page 17 – we recommend the Drafting Team to include a legend that clearly shows what each line means. This figure shows numerous lines (e.g., vertical, horizontal, etc.) that can lead to confusion.
3. Equation II.3, page 18, is missing the equal '=' sign (Epeak = ...)

Likes 0	
Dislikes 0	

Response	
Joshua Eason - Joshua Eason On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Joshua Eason	
Answer	No
Document Name	
Comment	

While ISO-NE supports the supplemental event, it believes that the probability of the event occurring in the lower 48 state portion of the United States is far less than once in one hundred years. The magnitude of enhancement is based on measurements from the IMAGE magnetometer stations which are located in northern Europe, rather than observations in the United States. Also, the four examples in the Supplemental Geomagnetic Event Description in Figures I-4,5,6 &7 all occur in far northern latitudes and it is not clear that these events will occur in more southern latitudes.

Likes 0	
Dislikes 0	

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

see comments to Question 1.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC

Answer	No
Document Name	

Comment

See comments to Question 1.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

We think that we are still at the infancy of understanding the nature and mechanism of these local enhancements. The Geophysics need more time to study this phenomenon and figure out how to simulate it in our GIC Simulator.

Are the current state of the art assessment tools capable of modeling a “local” enhancement? Given the tools limitations, Transmission Planners will likely model the supplemental GMD event as a uniform field over the entire assessment area. It is not clear whether this is acceptable or whether this stress transformers in a similar way as a non-uniform field analysis.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment
TPLTF Discussion: The group recognizes that there are multiple methods to approach revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data (FERC Order No. 830 Paragraph 44). However, given a wide diversity in available data, analytical tools, and personnel expertise, the group believes that the SDT has found a practical approach to meeting the objective of the FERC directive. Moreover, the *Supplemental GMD Event Description* white paper presents a reasoned justification for the use of the geoelectric field amplitude of 12 V/km. The group recommends that the SDT consider a less ambiguous name for the Supplemental GMD Event; the group believes *Extreme Value GMD Event* would be more appropriate for the following reasons: {C}a. {C}Implies a closer relationship to the extreme events of TPL-001-4 for which Planning Coordinators and Transmission Planners are familiar. {C}b. {C}Is better aligned with the extreme value statistical analysis that was conducted to produce the subject reference peak geoelectric field amplitude. {C}c. {C}Indicates a measure of how rare the extreme value for the 1-in-100 year peak geoelectric field amplitude may be, based upon the 95% confidence interval of the extreme value. While the group agrees that the application of extreme value statistical methods presented in the *Supplemental GMD Event Description* white paper is sound, three clarifying statements should be made in the white paper. Firstly, in short, the group agrees that by using the 23 years of daily maximum geoelectric field amplitudes from IMAGE magnetometers, a proxy of higher magnitude events can be characterized. It is noted that the southernmost magnetometer in the IMAGE chain resides in Suwałki, Poland at 54.01°N, whose geographic latitude places it roughly 500 miles north of Quebec. Given that geoelectric field is highly correlated with geomagnetic latitude rather than geographic latitude, the IMAGE data should still be referred to as a loose approximation for estimated North American geoelectric field magnitudes (Suwałki, Poland geomagnetic dipole latitude 52°N, Quebec geomagnetic dipole latitude 56°N). In other words, the group believes it is appropriate to qualify that the extreme value analysis performed in the white paper is based upon maximum data points obtained from an array of northern geomagnetically-biased latitudes, further inflated by using the high earth conductivity of Quebec. Secondly, it is well known that coastal geological conditions can lead to locally-enhanced geoelectric fields, not observed in regions more distant from the coast. Given that nearly all of the IMAGE chain magnetometers reside within 100 miles of the northern Atlantic Ocean or Baltic Sea coasts, it is reasonable to conclude that the geoelectric field amplitudes derived from the corresponding IMAGE data may have suffered from geoelectric field enhancement along conductivity boundaries. With respect to serving as a proxy for mainland North American peak geoelectric field amplitude, the SDT should consider further qualifying the appropriateness of the IMAGE data which served as the foundation of the extreme value analysis. Finally, the group agrees that the use of more resolute point over threshold (POT) methods was indicated over generalized extreme value (GEV). For clarity, however, it should be emphasized that the geoelectric field amplitude of 12 V/km represents the *extreme value* of the upper limit of the 95 percent confidence interval for a 100-year return interval. In other words, the statistical significance of the extreme value confidence interval is not equivalent to the statistic expressed by the confidence interval for the data set consisting of 23 years of all sampled geoelectric field amplitudes (not shown). Each of these considerations, if addressed, can strengthen the conclusions of the white paper by emphasizing its conservative approach.

Likes 0	
Dislikes 0	

Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
While IRC supports the supplemental event description, it believes that the probability of this event occurring in the lower 48 state portion of the United States is far less than once in one hundred years. The magnitude of enhancement is based on measurements from the IMAGE magnetometer stations which are located in northern Europe, rather than observations in the United States. Also, the four examples in the Supplemental Geomagnetic Event Description in Figures I-4, 5, 6 & 7 all occur in far northern latitudes and it is not clear that these events will occur in more southern latitudes.	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

The SPP Standards Review Group recognizes that there are multiple methods to approach revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data (FERC Order No. 830 Paragraph 44). However, given a wide diversity in available data, analytical tools, and personnel expertise, the group believes that the SDT has found a practical approach to meeting the objective of the FERC directive. Moreover, the Supplemental GMD Event Description white paper presents a reasoned justification for the use of the geoelectric field amplitude of 12 V/km.

We recommend that the SDT consider a less ambiguous name for the Supplemental GMD Event; the group believes Extreme Value GMD Event would be more appropriate for the following reasons:

1. Implies a closer relationship to the extreme events of TPL-001-4 for which Planning Coordinators and Transmission Planners are familiar.
2. Is better aligned with the extreme value statistical analysis that was conducted to produce the subject reference peak geoelectric field amplitude.
3. Indicates a measure of how rare the extreme value for the 1-in-100 year peak geoelectric field amplitude may be, based upon the 95% confidence interval of the extreme value.

While we agree that the application of extreme value statistical methods presented in the Supplemental GMD Event Description white paper is sound, three clarifying statements should be made in the white paper. Firstly, in short, the group agrees that by using the 23 years of daily maximum geoelectric field amplitudes from IMAGE magnetometers, a proxy of higher magnitude events can be characterized. It is noted that the southernmost magnetometer in the IMAGE chain resides in Suwałki, Poland at 54.01°N, whose geographic latitude places it roughly 500 miles north of Quebec. Given that geoelectric field is highly correlated with geomagnetic latitude rather than geographic latitude, the IMAGE data should still be referred to as a loose approximation for estimated North American geoelectric field magnitudes (Suwałki, Poland geomagnetic dipole latitude 52°N,

Quebec geomagnetic dipole latitude 56°N). In other words, the group believes it is appropriate to qualify that the extreme value analysis performed in the white paper is based upon maximum data points obtained from an array of northern geomagnetically-biased latitudes, further inflated by using the high earth conductivity of Quebec. Secondly, it is well known that coastal geological conditions can lead to locally-enhanced geoelectric fields, not observed in regions more distant from the coast. Given that nearly all of the IMAGE chain magnetometers reside within 100 miles of the northern Atlantic Ocean or Baltic Sea coasts, it is reasonable to conclude that the geoelectric field amplitudes derived from the corresponding IMAGE data may have suffered from geoelectric field enhancement along conductivity boundaries. With respect to serving as a proxy for mainland North American peak geoelectric field amplitude, the SDT should consider further qualifying the appropriateness of the IMAGE data which served as the foundation of the extreme value analysis. Finally, the group agrees that the use of more resolute point over threshold (POT) methods was indicated over generalized extreme value (GEV). For clarity, however, it should be emphasized that the geoelectric field amplitude of 12 V/km represents the extreme value of the upper limit of the 95 percent confidence interval for a 100-year return interval. In other words, the statistical significance of the extreme value confidence interval is not equivalent to the statistic expressed by the confidence interval for the data set consisting of 23 years of all sampled geoelectric field amplitudes (not shown). Each of these considerations, if addressed, can strengthen the conclusions of the white paper by emphasizing its conservative approach.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	Yes
Document Name	

Comment

The supplemental GMD event definition was determined through statistical analysis of available geomagnetic field data and corresponding calculations. The same data set and similar techniques were used in defining the benchmark GMD event with the exception that the supplemental definition was based on observations at each individual station vs. spatially averaging.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	

Comment

CenterPoint Energy agrees with the proposed supplemental GMD event and the description in the white paper. CenterPoint Energy believes the conservative approach is appropriate and reasonable and is the result of successful collaboration between GMD research experts, the space agency experts, and modeling experts from the power industry.

Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Applying a higher magnitude, localized event would seem to be prudent for assessing that type of phenomenon per FERC's request.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP agrees with the methodology behind the *Supplemental GMD Event Description,* but has concerns with how the standard has been revised to perform two separate assessments.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Buyce - City Utilities of Springfield, Missouri - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
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 Hydro One, HQ and IESO	
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: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Colby Bellville - Colby Bellville On Behalf of: Dale Goodwine, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
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	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Huitt - Xcel Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Thomas Rafferty - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
While OPG agrees with the technical content of the Supplemental GMD Event Description white paper the SDT approach ends up with two type of GMD events the Benchmark and the Supplemental; OPG is of the opinion that they should be amalgamated in one GMD type of events (albeit this may require GMD benchmark event definition revision). As stated in question #1 OPG believes that Supplemental GMD event assessment will render the Benchmark GMD event assessment obsolete (based on the more stringent condition) and thus will be an unnecessary budgetary burden.	
Likes 0	
Dislikes 0	
Response	

Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	
Document Name	
Comment	
We do not agree or disagree with the white paper. We believe that our industry's experience with GMD is not mature enough to adopt one specific approach to GMD assessment. The existing and recently developed assessment methodologies can be eventually verified by allowing the industry to collect GMD monitoring data and do further research. Again, we disagree with the standard specifying methodologies for the responsible entities. We believe that this approach should be an option (in the guidelines or documented as an implementation guidance) but not the only option.	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
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	

3. The SDT established an 85 A per phase screening criterion for determining which power transformers are required to be assessed for thermal impacts from a supplemental GMD event in Requirement R10. Justification for this threshold is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment* white paper. Do you agree with the proposed 85 A per phase screening criterion and the technical justification for this criterion that has been added to the white paper? If you do not agree, or if you agree but have comments or suggestions for the screening criterion and revisions to the white paper provide your recommendation and explanation.

Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
The technical basis is not clear. The standard references 2-5 minutes for the supplemental event, but this timeframe is not clearly referenced within the thermal impact assessment white paper.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Both benchmarked and supplemental GMD calculations attempt to limit the hot spot to 172 degrees as a screening criterion. Given the lower probability of the local 12 V/km GMD enhancements, perhaps the full 200C could be utilized and a screening criteria closer to 150 A used before a full thermal assessment is undertaken.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Requirement R6 requires a thermal impact assessment for applicable BES power transformers where the maximum effective GIC value required in Requirement 5, Part 5.1 is 75 A per phase or greater. Requirement R10 requires a supplemental thermal impact assessment for applicable BES power	

transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1 is 85 A per phase or greater. AZPS is concerned that the use of two (2) different thresholds in different analyses (benchmark and supplemental) increases the potential for inconsistency in the results of the assessments. Accordingly, AZPS suggests using a consistent value per phase in both the primary and the supplemental assessments. While AZPS would recommend a single 85 A per phase or greater for consistency, its request is primarily for consistency, which could be achieved at either value.

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

The screening threshold of 75 A per phase used in the benchmark GMD event should also be used in the thermal impact assessment for the supplemental GMD event because it was determined to be the appropriate value to ensure protection of the transformer.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	No
Document Name	

Comment

The supplemental GMD waveform used as a justification to develop the 85A screening criteria is not provided, similar to that which is provided in Figure 2 for the benchmark event in the “Screening Criterion for Transformer Thermal Impact Assessment” white paper. Therefore, the relationship between the supplemental waveform and hot-spot results shown in Figure 3 cannot be fully understood. Additionally, it is not stated which geo-electric scaling factor (B) was used for the supplemental event.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	No

Document Name	
Comment	
. There should be a threshold of greater than 500 MVA, similar to CIP standards: High, Medium, and Low impact rating criteria.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
There should be a threshold of greater than 500 MVA, similar to CIP standards: High, Medium, and Low impact rating criteria.	
Likes 0	
Dislikes 0	
Response	
William Harris - Foundation for Resilient Societies - 8	
Answer	No
Document Name	
Comment	
Sudden reversal events can occur at far lower theshholds. A high dB/dT can occur during a relatively weak GMD event. Perhaps sensible to have two typoes of hazard, but if the thresholds are to high, the grid will not be protected. 20 amps per phase would be consistewnt with INL testing of 138 kV tranasformer in year 2013,. Generator equipment is also susceptible to GMD damage well below 75 amps per phase.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	

Comment	
Agree with the proposed screening criteria of 85 A per phase for the Supplemental Event as the threshold for assessing power transformers since it is consistent with the screening criteria used to establish the 75 A per phase threshold for the Benchmark Event.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP agrees with the 85A criterion, but is concerned about the potential duplication of work driven by the need to perform two separate assessments.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
While the 85 Amps per phase screening criterion is acceptable, it should be noted that the GIC flow values are dependent on the accuracy of the modeling program from which they are derived. For test cases that have been run using the latest version of GIC modeling and software, there were significant large currents in excess of 85 Amps in the boundary areas of observation. This behavior is analogous with the slack or swing buses that are used in AC power flow analysis. Specifically, the boundary buses take on whatever resulting flows will enable a solution for the GIC model flow, without taking into regard any structures that exist beyond these points. As a result, the boundary current flow conditions are not an accurate representation of the anticipated neutral and phase flow conditions, and if taken at face value, would result in unnecessary corrective actions to be taken. It is therefore critical that all modeling efforts anticipate these conditions to occur and ensure that the models are sufficiently adequate in size and scope to provide accurate results within the regions of interest, as well as to interpret any anomalies that might arise from artificial limitations of the GIC modeling programs.	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	08_SPP TPLTF Discussion Summary on 1st Release TPL-007-2.docx
Comment	
please see attached form completed by the TPL-Task Force	
Likes 0	
Dislikes 0	
Response	

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy agrees with the approach used by the SDT to arrive at 85 A per phase as a screening criterion for determining which power transformers are required to be assessed for thermal impacts from a supplemental GMD event in R10. CenterPoint Energy appreciates the diligent efforts of the SDT in ensuring consistency between the approach used to develop the screening criterion in R10 and the approach used to develop the screening criterion in R6.	
Likes 0	
Dislikes 0	
Response	

Joshua Eason - Joshua Eason On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Joshua Eason	
Answer	Yes
Document Name	
Comment	
Based on comparing Tables 1 and 2 in the Screen Criterion for Transformer Thermal Impact Assessment, the 85 Ampere screening criteria is as conservative as the 75 Ampere screening criteria associated with the benchmark event.	
Likes 0	
Dislikes 0	
Response	

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
As the supplemental event is more severe than the benchmark event, we agree that the threshold for transformer thermal assessment should correspondingly be raised as well. Through analysis, the SDT determined that 85 A per phase was a conservative threshold to apply for the supplemental event.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Just a question, but have transformer manufacturers been asked if they agree that 85 A is an acceptable threshold for all of their transformer designs (core-form, shell-form), configurations (3-phase autotransformers, 1-phase autotransformers, 3-phase delta-wye transformers, etc.), and vintages (old, new)?	
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 Hydro One, HQ and IESO	
Answer	Yes
Document Name	
Comment	
While the 85 Amps per phase screening criterion is acceptable, it should be noted that the GIC flow values are dependent on the accuracy of the modeling program from which they are derived. For test cases that have been run using the latest version of GIC modeling and software, there were significant large currents in excess of 85 Amps in the boundary areas of observation. This behavior is analogous with the slack or swing buses that are used in AC power flow analysis. Specifically, the boundary buses take on whatever resulting flows will enable a solution for the GIC model flow, without taking into regard any structures that exist beyond these points. As a result, the boundary current flow conditions are not an accurate representation of the anticipated neutral and phase flow conditions, and if taken at face value, would result in unnecessary corrective actions to be taken. It is therefore critical that all modeling efforts anticipate these conditions to occur and ensure that the models are sufficiently adequate in size and scope to provide	

accurate results within the regions of interest, as well as to interpret any anomalies that might arise from artificial limitations of the GIC modeling programs.

"Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event" from the screening criterion document provides a useful visual, can the drafting team additionally provide a similar chart and the data for the supplemental GMD event?

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	2013-03_IB_Comment_Form_June_2017_svm.docx

Comment

Given the use of the 12 V/km geoelectric field amplitude for the supplemental GMD event, the SPP Standards Review Group agrees with the proposed 85 Amp threshold justified in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper. We suggest that the proposed change on page 11 of the white paper stating "because the supplemental waveform has a sharper peak, the peak metallic hot spot temperatures associated with the supplemental waveform are slightly lower than those associated with the benchmark waveform" be clarified. In other words, this statement is counterintuitive given that the increased supplemental time-series waveform peak value implies higher GIC flows that, when experienced by a transformer will lead potentially higher metallic hot spot temperatures.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	Yes
Document Name	

Comment

Based on comparing Tables 1 and 2 in the Screen Criterion for Transformer Thermal Impact Assessment, the 85 Ampere screening criterion is as conservative as the 75 Ampere screening criteria associated with the benchmark event.

Likes 0	
Dislikes 0	

Response

Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Huitt - Xcel Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Colby Bellville On Behalf of: Dale Goodwine, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
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	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Buyce - City Utilities of Springfield, Missouri - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
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	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	
Document Name	
Comment	
Consistent with our comments above, it should be up to the responsible entity to decide what the appropriate threshold is based on the responsible entities justification, risk assessment, and risk tolerance level. The whitepapers or any other research can be used to support the justification.	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	

Thomas Rafferty - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

4. The SDT revised the *Transformer Thermal Impact Assessment* white paper to include the supplemental GMD event. Do you agree with the revisions to the white paper? If you do not agree, or if you agree but have comments or suggestions on the revisions to the white paper provide your recommendation and explanation.

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
There should be a threshold of greater than 500 MVA, similar to CIP standards: High, Medium, and Low impact rating criteria.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
There should be a threshold of greater than 500 MVA, similar to CIP standards: High, Medium, and Low impact rating criteria.	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
NERC's Screening Criterion for Transformer Thermal Impact Assessment and Transformer Thermal Impact Assessment White Paper state that TPL-007-2 R6 and R10 analyses can in some cases be addressed simply by comparing Screening Criterion for Transformer Thermal Impact Assessment Table 1 and 2 values to IEEE emergency loading criteria. The statement in footnote 5 of the Transformer Thermal Impact Assessment White Paper that the "peak GIC(t)" value is to used in this exercise may cause some confusion, however. This appears to be the "maximum effective GIC" reported in R5.1 and R9.1 of TPL-007-2, given that the Screening Criterion for Transformer Thermal Impact Assessment uses the term "effective GIC" in discussing Tables 1 and 2, but it's difficult to be certain without a clarification or (better) harmonization of terms between the standard and its supporting material.	

NERC should provide default tables by transformer type (single phase, 5-legged core 3-phase, etc) similar to Table 1and 2 for cases in which the first-cut process discussed above does not demonstrate that transformers are acceptable as-is, since the alternatives in the Thermal Impact Assessment and Transformer Thermal Impact Assessment White Paper will often prove impractical. OEM GIC capability curves are seldom available, and the same is true for the input data needed for thermal response simulations. Rather than making every GO and TO in North America seek out consultants with generic information in these respects (if there are any) it would be better to simply present the best available OK/not-OK boundaries up-front.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

We believe that we need more experience with GMD before moving on to include more time consuming analysis. We also noticed that, Figure 1 and Figure 3 in the *Screening Criterion for Transformer Thermal Impact Assessment* are on different temperature scales (80-300 vs 0-300) so they are difficult to compare.

Likes 0	
Dislikes 0	

Response

Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance

Answer	No
Document Name	

Comment

The standard references 2-5 minutes for the supplemental event, but this timeframe is not clearly referenced within the thermal impact assessment white paper.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	Yes

Document Name	
Comment	
Figure 17 indicates that the load is at the 70% level, but the previous paragraph states that the load is at the 75% level. It is unclear whether the chart or just the description needs to be revised.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group agrees with the changes in the *Transformer Thermal Impact Assessment* white paper, with the exception of the explanation provided for Table 2 on page 5. Similar to the comment made regarding the counterintuitive language in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper, it is not clear why metallic hot spot temperatures are reduced for the supplemental GMD event for the same effective GIC and transformer bulk oil temperature. Additional clarity on this point would improve the ability of applicable entities to rely upon the reference data provided. The group recommends adding white paper language similar to that suggested in Question Q3. The group would like to highlight that the study of supplemental GMD event conditions may cause a significantly larger number of transformers to be added for assessed by Transmission Owners and Generator Owners. Given that the analytical tools and modeling software available for this type of analysis are limited, as well as the fact that most manufacturers supplying power transformers to U.S. customers do not include data necessary to complete detailed thermal modeling with transformer test reports, the additional effort to satisfy the supplemental GMD event analysis will be arduous. The group recommends that the SDT consider the reality that these tools are merely in their infancy across the industry, and additional time to develop, deploy, and train on them should be included in the TPL-007-2 implementation plan to complete transformer thermal assessments for the supplemental GMD event.	
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 Hydro One, HQ and IESO	
Answer	Yes
Document Name	
Comment	
Table 1 and 2 are useful to show the differences between the benchmark event and the supplemental, but some of the figures are not clear which GMD event was used to generate the GIC(t) time series. Can some additional language be added to clarify the GMD event of the figures in this document?	

Also, there was some inconsistency in axis labels and units between the various figures, which makes it difficult to draw conclusions when comparing the charts. For example: A/phase versus Amps, minutes versus hours for the time scale. Can these charts be updated with uniform axis labels and units for comparative purposes?	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Per FERC's directive, the transformer thermal assessment was revised to not rely solely on spatially-averaged data and the SDT modified the standard to utilize the supplemental GMD event definition for the additional analysis requested by FERC.	
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	
We agree with the revisions to the white paper but disagree with the 85 A screening criterion as this may cause damage to the transformers because a thermal assessment will not be performed until 85 A.	
Likes 0	
Dislikes 0	
Response	
Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

CenterPoint Energy agrees with the revisions to include the supplemental GMD event in the Transformer Thermal Impact Assessment white paper.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

TPLTF Discussion: The group agrees with the changes in the *Transformer Thermal Impact Assessment* white paper, with the exception of the explanation provided for Table 2 on page 5. Similar to the comment made regarding the counterintuitive language in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper, it is not clear why metallic hot spot temperatures are reduced for the supplemental GMD event for the same effective GIC and transformer bulk oil temperature. Additional clarity on this point would improve the ability of applicable entities to rely upon the reference data provided. The group recommends adding white paper language similar to that suggested in Question Q3.

The group would like to highlight that the study of supplemental GMD event conditions may cause a significantly larger number of transformers to be added for assessed by Transmission Owners and Generator Owners. Given that the analytical tools and modeling software available for this type of analysis are limited, as well as the fact that most manufacturers supplying power transformers to U.S. customers do not include data necessary to complete detailed thermal modeling with transformer test reports, the additional effort to satisfy the supplemental GMD event analysis will be arduous. The group recommends that the SDT consider the reality that these tools are merely in their infancy across the industry, and additional time to develop, deploy, and train on them should be included in the TPL-007-2 implementation plan to complete transformer thermal assessments for the supplemental GMD event.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Buyce - City Utilities of Springfield, Missouri - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
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	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Colby Bellville On Behalf of: Dale Goodwine, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Eason - Joshua Eason On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Joshua Eason	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Huitt - Xcel Energy, Inc. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Thomas Rafferty - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	

Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	
Document Name	
Comment	
Consistent with our comments above, it should be up to the responsible entity to decide what the appropriate threshold is based on the responsible entities justification, risk assessment, and risk tolerance level. The whitepapers or any other research can be used to support the justification.	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
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	

5. The SDT developed proposed Requirement R7 to address FERC directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments (P. 101, 102). Do you agree with the proposed requirement? If you do not agree, or if you agree but have comments or suggestions for the proposed requirement provide your recommendation and explanation.

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

The language used in R7 needs to clarify the type of "year" used in the deadlines of the CAP. Is this "Calendar Year" or "Calendar Months"? Please clarify. Also, AEP seeks clarification on whether a CAP is required or expected in response to the Thermal Impact Assessments from R6. If it is, then there may be a conflict in the timelines for the execution of R4 and R6 and the timeline for the development of a CAP as per R7.

Likes 0	
Dislikes 0	

Response

Shawn Abrams - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Santee Cooper has concerns that NERC/FERC is in essence directing entities to implement Corrective Action Plans which violates the Energy Policy Act of 2005. This revision of TPL-007 actually has a requirement to implement Corrective Action Plans within a specified period after their development.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

Manitoba Hydro cannot adopt R7 as is as it violates *The Manitoba Hydro Act*. Manitoba Hydro does not support hard coding the timelines for implementing a corrective action plan in the standard. The timelines are a function of a large number of factors that are out of the control of the

Transmission Planner – including securing the necessary resources. Corporate annual capital spending is limited and is prioritized based on a number of factors. Securing funding to protect for a 1/100 year event could have lower associated risks to BES reliability than other projects, meaning timeline discretion for the Transmission Planner to address risks is important.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC	
Answer	No
Document Name	
Comment	
We have concerns that the first time the evaluation of the TPL-007 will take place, the corrective action plans may take more time than the R7 requirements. We agree with the deadlines for the second time the evaluation will be done.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
We have concerns that the first time the evaluation of the TPL-007 will take place, the corrective action plans may take more time than the R7 requirements. We agree with the deadlines for the second time the evaluation will be done.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	No
Document Name	
Comment	

Will the TO and GO have any input in the selection of the mitigation actions?

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	No
Document Name	

Comment

There are specific timetable for implementing the CAP and additional administrative burden placed on the responsible entity if the timetable is not met; therefore, an additional requirement should be added to the standard to require any functional entity referenced in a CAP to implement the CAP identified by the responsible entity.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy disagrees with the prescriptive timeframes identified in R7.3.1 and R7.3.2. and recommends eliminating R7.3 in its entirety. Requiring a specific timeframe for mitigation implementation is overly prescriptive and unprecedented for a NERC standard. The specifics of an implementation timeline should be developed by the responsible entities with more intimate knowledge and understanding of their systems. The compliance burden of this requirement does not provide commensurate reliability benefits.

If R7.3 is not eliminated as recommended above, CenterPoint Energy supports R7.4 but recommends that the first sentence of R7.4 be reworded as follows:

R7.4 Be revised if responsible entity cannot implement the CAP within the timetable provided in R7.3.

Likes 0	
Dislikes 0	

Response

Joshua Eason - Joshua Eason On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Joshua Eason	
Answer	No
Document Name	
Comment	
ISO-NE is supportive of the proposed R7 as long as any delays with implementing a CAP due to tariff requirements for engaging a stakeholder planning process when developing system upgrades associated with a CAP are considered to be “beyond the control of the responsible entity.” Further, ISO-NE is encouraged that the implementation plan for TPL-007-2 includes a one year period between the completion of the vulnerability assessment in R4 and the completion of any needed CAPs according to R7. ISO-NE believes that this is in acknowledgement that the analysis in R4 (and possible in R6) may need to be repeated during the development of CAPs due to the iterative nature of the CAP development 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	
The hardware mitigation timeline mentioned in the requirement R7 does not address the complexities in building the project like regulatory approvals, construction clearances on existing equipment, Right of Way requirements, etc.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The four-year hardware implementation deadline in R7.3.2 may be impractical, especially if need for a large number of entities to install GIC blocking devices leads to extended lead-times for this equipment. The same issue was thoroughly investigated by the PRC-025 SDT (see the Implementation Plan for this standard), leading to an 84-months deadline, and we recommend that the TPL-007-2 SDT follow this precedent.	
Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
We agree with the addition of the proposed Requirement R7 to TPL-007-2, however we are concerned with the possible required timeframe for implementation. Determining appropriate mitigations involves iterative evaluations and solutions. The solutions may involve a number of TOs and various stakeholder (ISOs/RTOs, governmental bodies, market participants) input may be required as well. The timing requirements should recognize and allow for delays out of the control of the good-faith effort of the responsible entity. Given that GIC assessment and mitigation is a new topic, it is likely that significant time will be required to achieve regional consensus on the appropriate mitigation plan.	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG does not agree with the implementation deadlines: R7.2 provides one year for the CAP; this has not been performed before and the timeline may not be realistic. As stated in the additional comments: - The four years deadline to implement all the hardware mitigation action may provide unfair market advantage to the unaffected/ less affected TOP, GOP due to the time/resources/financial effort involved. Continued operation should be allowed if there is a shortage of hardware, or the lead time to design/procure/implement complete hardware solution exceeds the four years duration. - The two years deadline to implement all the non-hardware solution may provide unfair market advantage to the unaffected/less affected TOP, GOP, as the implementation for a large scale TOP, GOP will take more time, resources/financial effort and may require commissioning and studies.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	

Answer	No
Document Name	
Comment	

The revision identifies the need to have implementation of non-hardware and hardware mitigations within two and four years of CAP development, respectively. However, there is no technical guidance within the standard that identifies the difference between these mitigations. According to the FERC Order, GIC blocking or monitoring devices are identified as hardware mitigations. Similar references are listed within the NERC Geomagnetic Disturbance Planning Guide. We believe these references should be directly incorporated into the requirement, and replace hardware with GIC reduction or similar devices.

Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1

Answer	No
Document Name	
Comment	

The deadlines specified in R7.3.1 and R7.3.2 are ambiguous. Using the term “development” does not offer a specified date to measure the 2- or 4-year installation requirements. To provide clarity for those needing to implement the mitigation, please consider replacing “development of CAP” with “final approval of CAP by the Planning Coordinator or Transmission Planner.”

R7 does not provide a method to address situations where the responsible entity knows that the selected mitigation cannot meet the 2- or 4-year deadline during the development of the CAP. As the standard currently states, a CAP would need to be developed with the specified deadlines in R7.3 and then immediately revised to address the known situations instead of identifying the appropriate timeline during the development of the CAP. Consider revising R7.4 such that it is not specific to revisions to a CAP only to address these situations.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 5

Answer	No
Document Name	
Comment	

Increased costs do not justify the low, if any, reliability benefits. There should be a threshold of greater than 500 MVA, similar to CIP standards: High, Medium, and Low impact rating criteria.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Tri-State has concern that as written, the TP/PC can create a CAP that the implementing entity (another TO/GO) may have issues with. It seems the TP/PC has ultimate control on what the CAP is without taking into account that the implementing entity may have other thoughts or differing opinions. In a situation where a TO/GO states that they are unable to implement a CAP given to them by another TP/PC, what recourse does the TP/PC have? If an agreement cannot be reached amongst the planning and implementing entities, then what are the next steps to be taken?	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Increased costs do not justify the low, if any, reliability benefits. There should be a threshold of greater than 500 MVA, similar to CIP standards: High, Medium, and Low impact rating criteria.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	

Comment
The NSRF believes a definition/example of what “hardware” means in this context is needed. Order 830 in P 82. Says: *NERC states that Reliability Standard TPL-007-1 contains “requirements to develop the models, studies, and assessments necessary to build a picture of overall GMD vulnerability and identify where mitigation measures may be necessary.” NERC explains that mitigating strategies “may include* ***installation of hardware (e.g., GIC blocking or monitoring devices)****, equipment upgrades, training, or enhanced Operating Procedures.* Therefore, hardware may only mean GIC blocking or monitoring devices, but it can also include equipment upgrades.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment
TPLTF Discussion: Given the specificity of the Paragraphs 101 and 102 directives of FERC Order No. 830 Paragraph 44, the group believes that the SDT had little flexibility when developing the proposed language of Requirement R7. The group agrees with the proposed Requirement R7, as presented. The group would like to reiterate the suggestion that the Supplemental GMD Event nomenclature be changed to Extreme Value GMD Event, as explained in the group’s discussion of Question Q2.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment
The NSRF believes a definition/example of what “hardware” means in this context is needed. Order 830 in P 82. Says: *NERC states that Reliability Standard TPL-007-1 contains “requirements to develop the models, studies, and assessments necessary to build a picture of overall GMD vulnerability and identify where mitigation measures may be necessary.” NERC explains that mitigating strategies “may include* ***installation of hardware (e.g., GIC blocking or monitoring devices)****, equipment upgrades, training, or enhanced Operating Procedures.*

Therefore, hardware may only mean GIC blocking or monitoring devices, but it can also include equipment upgrades.

Likes 1	Darnez Gresham, N/A, Gresham Darnez
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

SRP requests clarification of the phrase "one year" used in 7.2, such as "one calendar year" or "15 months".

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	Yes
Document Name	

Comment

The deadlines appear to be reasonable (1 year to come up with a CAP when required; 2-years from CAP determination to implement any non-hardware related solutions; 4-years from CAP determination to implement any hardware related solutions; and exceptions for not meeting deadlines for factors beyond the control of the responsible entity)

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Given the specificity of the Paragraphs 101 and 102 directives of FERC Order No. 830 Paragraph 44, the SPP Standards Review Group believes that the SDT had little flexibility when developing the proposed language of Requirement R7. We agree with the proposed Requirement R7, as presented.

The group would like to reiterate the suggestion that the Supplemental GMD Event nomenclature be changed to Extreme Value GMD Event, as explained in the group's discussion of Question Q2.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	Yes
Document Name	

Comment

IRC agrees with the proposed deadlines as long as any delays with implementing a CAP due to tariff or regional requirements for conducting a stakeholder planning process when developing system upgrades associated with a CAP are considered to be "beyond the control of the responsible entity." Further, IRC is encouraged that the implementation plan for TPL-007-2 includes a one year period between the completion of the vulnerability assessment in R4 and the completion of any needed CAPs according to R7. IRC believes that this is in acknowledgement that the analysis in R4 (and possibly R6) may need to be repeated during the development of CAPs due to the iterative nature of the CAP development process.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Huitt - Xcel Energy, Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Colby Bellville - Colby Bellville On Behalf of: Dale Goodwine, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
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 Hydro One, HQ and IESO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Michael Buyce - City Utilities of Springfield, Missouri - 1
Answer	Yes
Document Name	
Comment
Likes 0	
Dislikes 0	
Response
Rachel Coyne - Texas Reliability Entity, Inc. - 10
Answer	
Document Name	
Comment
Texas RE acknowledges the SDT made the decision to not require entities have a Corrective Action Plan for the supplemental GMD Vulnerability Assessment if the System does not meet the performance requirements indicated in Attachment 1. Requirement R8 Part 8.3 requires that if the supplemental GMD Vulnerability Assessment concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. Texas RE recommends the responsible entity also conduct an evaluation of possible actions designed to reduce the likelihood or mitigation the consequences and adverse impacts of voltage collapse and uncontrolled islanding.
Likes 0	
Dislikes 0	
Response
Thomas Rafferty - Edison International - Southern California Edison Company - 5
Answer	
Document Name	
Comment
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison
Likes 0	
Dislikes 0	

Response
Richard Vine - California ISO - 2
Answer	
Document Name	
Comment
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee
Likes 0	
Dislikes 0	
Response

6. The SDT developed Requirements R11 and R12 to address FERC directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data (P. 88; P. 90-92). Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

Comment #1:

Modify R11 and R12 to replace “Planning Coordinator Area” with the term “respective area” or “responsible area”. This is consistent with TPL-007-1 and TPL-001-4. See example below:

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its respective Planning Coordinator’s planning area.

Comment #2:

NSFR believes that the reference to “GMD measurement data” in R1 should be changed to align with the language in requirements R11 and R12. The term GMD measurement data is general and could can be interpreted to include data that is outside the scope of the standard. The NSRF suggest the following changes to R1:

R1. 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 GIC monitor data and geomagnetic field data GMD measurement data as specified in this standard.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

Increased costs do not justify the low, if any, reliability benefits

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Increased costs do not justify the low, if any, reliability benefits.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
The Rationale section for R11 and R12 and the Application Guidelines section for R11 include a statement about using Hall Effect transducers on the transformer neutrals. There are many technically correct approaches for monitoring geomagnetically induced currents and the standard should not inadvertently advocate for one method of monitoring over another. The statement should be removed and if necessary, include a reference to IEEE C57.163 which discusses monitoring. The R11 and R12 rationale section makes reference to the terms “geomagnetic field data” and “geomagnetic field data product”. What is the difference? The term “product” should be clarified.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe the requirements should clarify expected processes once GIC monitoring and magnetometer data is collected. Are responsible entities expected to include this information in their models that are required for Requirement R2? Are they expected to provide this information to their Reliability Coordinator for inclusion in its GMD Operating Plan in NERC Reliability Standard EOP-010-1? We believe the associated FERC directives could be incorporated into Requirement R1, which already requires an entity-coordinated process to identify the collection of GMD data measurements. We see benefits in enhancing Requirement R1 to include subparts for maintaining models, performing studies for	

GMD Vulnerability Assessments, and GIC monitoring and magnetometer data collection, including within its associated Violation Severity Limits.

2. The reference to the collection of data for the entire Planning Coordination Area is too broad and burdensome for the applicability of these requirements. We believe the identified collection area should be reflective of the applicability, to that of the responsible entity's planning area.

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

1. Paragraph 2, page 11 of 42 of proposed TPL-007-2, under GMD Measurement Data Process (blue box) – the Drafting Team states that " Technical considerations for GIC monitoring are contained in Chapter 6 of the 2012 Special Reliability..." This information is contained in Chapter 9 and not in Chapter 6 of the Interim Report. Please update this section as well as the first sentence immediately under R11 in page 38 of 42. In addition, we recommend that the Drafting Team includes a link to the report as it is difficult to find.

2. Requirement 12, page 12 or 42, requires that "Each responsible entity...shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area." This requirement appears to be in direct contradiction to the last sentence contained inside the 'blue box' same page; which states: "The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area". We request clarification. And, if the magnetometer data needs to be extrapolated, we recommend that the drafting team provides guidance.

3. Draft 1 of TPL-007-2, page 38 of 42, under Monitor specifications –

    i. monitor data range (i.e., -500 A to +500 A CT), will this monitor specification be a recommendation or requirement? We recommend the Drafting Team to provide clarification. Note this section references the NERC 2012 GMD report and in the 2012 report it is stated "The DC sensor should accommodate at least +/- 500 amps of DC current...". Referencing the 2012 GMD Report creates confusion.

    ii. ambient temperature ratings, we recommend the SDT to provide clarification; i.e., does the monitor need to include the ability to measure ambient temperature and should we log the station ambient temperatures.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

Depending on the size of the planning area, one GIC and magnetometer value may not provide sufficient data to accurately provide model validation. Some additional guidance would also be helpful for determining where to place monitoring equipment so that the equipment is installed in a location that can provide meaningful data. NV Energy would prefer the SDT consider adding additional details on determining the placement of equipment and consider adding detail to add more than one monitoring equipment when appropriate.

R11 and R12 requires data to be collected, but does not require anything to be done with the data. With no requirement to do anything with data collected, it seems like these two requirements place an unnecessary task on entities. Additionally, R12 allows entities to collect geomagnetic from sources such as observatories operated by the US Geological Survey. With no requirements to do anything with the data, R12 is asking entities to log onto a website and periodically collect data. NV Energy would like to see these standards expanded upon to require this data to be collected and then used for GMD model validation.

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

One GIC monitor and magnetometer value in the Planning Coordinator's planning area does not provide enough data to enable model validation and situational awareness

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	No
Document Name	

Comment

Magnetometers data are already available from Natural Resources Canada and from Universities research groups, therefore, there is no need to collect them.

In the control room, Hydro-Quebec monitors and collects the impact of GMDs by using voltage distortion level. GIC currents are also collected at different location on the network but they are not used in the control room. The acquisition of these data should be added to the EOP-010-1 reliability standard under the RC supervision and the RC shall transmit them as requested by the PC.

Hydro-Quebec supports initiatives that can be used to monitor and validate, with real measures, the GMD’s impact on the network.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP supports AZPS’s response to question 6.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC	
Answer	No
Document Name	
Comment	
Magnetometers data are already available from Natural Resources Canada and from Universities research groups, therefore, there is no need to collect them. In the control room, Hydro-Quebec monitors and collects the impact of GMDs by using voltage distortion level. GIC currents are also collected at different location on the network but they are not used in the control room. The acquisition of these data should be added to the EOP-010-1 reliability standard under the RC supervision and the RC shall transmit them as requested by the PC. Hydro-Quebec supports initiatives that can be used to monitor and validate, with real measures, the GMD’s impact on the network.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	

Comment
Per Paragraph 91 of FERC Order No. 830, a transmission owner should be able to apply for an exemption from the GIC monitoring data collection requirement if it demonstrates that no or little value would be added to Planning and Operations. The capability to request such exemption is not, however, clearly indicated within Requirements R11 and R12. AZPS respectfully recommends that such language be included. AZPS further recommends that the SDT utilize language similar to that included in Requirement R10, which includes language that limits the need to [conduct a supplemental thermal impact assessment for applicable BES power transformers where the maximum effective GIC value provided in R9, Part 9.1 is 85 A per phase or greater]. AZPS proposes that similar language be added in Requirements R11 and R12 so that these requirements only apply where the maximum effective GIC value of applicable BES power transformers provided in R9, Part 9.1 is 85 A per phase or greater. Such would ensure that the same operational threshold is applied throughout these related requirements, providing consistency and an established threshold for determining need from the operational/planning perspective. Additionally, as noted in AZPS's comments to question 3 above, AZPS's request here is primarily for consistency and, while it recommends a threshold of 85 A per phase or greater, its recommendation could be achieved through the consistent application of that value or the 75 A per phase or greater.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment
It's nice to collect data but there's no requirement to do anything with the data, like perform model benchmarking. Collecting data from a single transformer and a single magnetometer may be insufficient to perform any reasonable benchmarking of GMD models. Perhaps this could be written in a style closer to MOD-033, for GMD model validation. The Transmission Planner would document their model validation process.

Likes 0	
Dislikes 0	

Response

Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance

Answer	No
Document Name	

Comment
The SDT should consider additional details on placement of the monitoring equipment to help guide the installations, similar to PRC-002 and DME. Or, the responsibility for equipment placement guidelines could be delegated (assigned) to the PC to develop at a more local level. Having wide-open equipment monitoring requirements may lead to a lot of wasted investment or inefficient monitoring.

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
American Electric Power does not believe R11 and R12 are explicitly clear in their intent, or state exactly who is required to meet the obligations. The latter may perhaps be inferred by R1, however AEP requests clarity and specificity within R11 and R12 themselves.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Despite the added cost to implement additional monitoring and data collection, the SPP Standards Review Group agrees that the SDT developed a reasonable approach to the FERC directives in Order No. 830 Paragraph 88.	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	

FERC required additional data for model validation and situational awareness purposes. The SDT developed requirements allow for the collection of GIC data and magnetometer data (which could come from existing monitoring equipment where available and appropriate) as opposed to necessarily mandating installation of new equipment to obtain the specified data. Responsible entities can thus partner with government agencies or research facilities that operate magnetometers to obtain some of the required data.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	

Comment

CenterPoint Energy agrees with the proposed requirement as written. Furthermore, CenterPoint Energy supports the Commission's determination in P. 92 that requiring data rather than requiring installation of GIC monitors and magnetometers affords greater flexibility while still obtaining benefits. However CenterPoint Energy would not support any revisions that would require installation of devices or the release of entity's protected information.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3

Answer	Yes
Document Name	

Comment

Will this result in a directive for a GO or TO to install GIC monitoring, or will the responsible entity simply get data from existing monitors in its area?

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment
Comment #1: Modify R11 and R12 to replace “Planning Coordinator Area” with the term “respective area” or “responsible area”. This is consistent with TPL-007-1 and TPL-001-4. See example below: **R12.** Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its respective Planning Coordinator’s planning area. **Comment #2:** NSFR believes that the reference to “GMD measurement data” in R1 should be changed to align with the language in requirements R11 and R12. The term GMD measurement data is general and could can be interpreted to include data that is outside the scope of the standard. The NSRF suggest the following changes to R1: R1. 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 GIC monitor data and geomagnetic field data GMD measurement data as specified in this standard.

Likes 1	Darnez Gresham, N/A, Gresham Darnez
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment
In R12, it is not clear how much geomagnetic field data, from a time & space perspective, the responsible entity would be required to obtain for its Planning Coordinator Planning Area.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
TPLTF Discussion: Despite the added cost to implement additional monitoring and data collection, the group agrees that the SDT developed a reasonable approach to the FERC directives in Order No. 830 Paragraph 88.	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
This will help refine future assessment requirements as to how applicable the Benchmark and Supplemental Event screening criteria are in comparison compared to actual recorded GMD events.	
Likes 0	
Dislikes 0	
Response	

William Harris - Foundation for Resilient Societies - 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Buyce - City Utilities of Springfield, Missouri - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
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 Hydro One, HQ and IESO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
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: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response

Joshua Eason - Joshua Eason On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Joshua Eason

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Gerry Huitt - Xcel Energy, Inc. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

Thomas Rafferty - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Ginny Beigel, City of Vero Beach, 3; Jeffrey Partington, Keys Energy Services, 4; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	
Document Name	
Comment	
We appreciate the SDT effort to satisfy the requirement of FERC Order No. 830 for the collection of GIC and Magnetometer Data. Currently, R11 and R12 only say to collect the data. We would encourage the drafting team to add language to R11 and R12 that the process document developed by the responsible entity point to the amount of data required, who collects it, who to give it to, and how long to maintain it.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Since the Rationale for Requirements R11 and R12 use the term “as necessary”, Texas RE recommends adding the term “as necessary” as a periodicity to the language of Requirements R11 and R12. Requirement R11 requires a GIC monitor located in the Planning Coordinator’s planning area. The map showing the USGS observatories (https://geomag.usgs.gov/monitoring/observatories/) indicates that there is not a USGS monitor in each PC’s planning area. There may be monitoring data available for GIC in the PC’s planning area that is not located within the planning area. Texas RE recommends revising the language to say *“Each*	

responsible entity…..from at least one GIC monitor that is monitoring equipment within the Planning Coordinator's planning area for each earth model represented…..".	
Likes 0	
Dislikes 0	
Response	

7. Do you agree with the proposed Implementation Plan for TPL-007-2? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer	No
Document Name	

Comment

Comments: The effective date of the revised Standard being only 3 months after FERC's approval is too short. There is no need to rush this new Standard as there are substantial revisions. Seminole recommends a minimum of 12 months after approval

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

There should be trial period for industry to gain understanding and knowledge of GMD before implementing a standard.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS requests more clarity regarding the due date of the supplemental assessment (TPL-007-2 Requirement R8). If the effective date of TPL-007-2 is before the January 1, 2021 and the studies are performed concurrently, what is the due date of the supplemental assessment (TPL-007-2 Requirement R8)? According to the implementation plan, both assessments would be due 42 months after the effective date of TPL-007-2. If such is an accurate statement of the appropriate study deadlines, AZPS requests that the SDT clarify this in its guidance, FAQs, or other document.

Likes 0	

Dislikes 0	

Response

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC	
Answer	No
Document Name	

Comment
See comments for Question 1.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	

Comment
It is not clear why there is a difference in compliance implementation dates for the various requirements between the two Implementation Plan options. It would seem logical that they both would have the same compliance implementation date with respect to the effective date of the Standard. There does not appear to be a compliance date for R6 if TPL-007-2 becomes effective on or after January 1, 2021. TPL-007-1 has a compliance date for R5 on January 1, 2019. It is not clear what this date would be if the new standard becomes effective before that date.

Likes 0	
Dislikes 0	

Response

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

Comment
See comments for Question 1.

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	No
Document Name	

Comment

The current implementation plan doesn't contain an implementation date for R1 which implies an effective date of the first day of the first calendar quarter that is three month after FERC approval. Planning Coordinators will need time to update their document identifying individual and joint responsibility to include the supplemental GMD Vulnerability Assessment and a process to obtain GMD measurement data. Entities should be given a minimum of 6 months after the approval of the standard to update R1 documentation since it does require coordination with Transmission Planners.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy disagrees with the proposed Implementation Plan for TPL-007-2. CenterPoint Energy recommends delaying the implementation of Requirement 8 through 10 until after one complete cycle of Requirements R4 through R6. CenterPoint Energy's recommendation is based on the following:

- The efforts already required for compliance with TPL-007-1 that necessitate data sharing, model building, process creation, and first-of-its-kind analysis are already significant. The analysis tools needed for completion of the Vulnerability Assessment required by TPL-007-1 are not available in the industry at this time. The NERC GMD Task Force identified Task 7 to develop tools for system-wide harmonic assessment; however, this task is not scheduled to be complete until the fourth quarter of 2019.
- The additional efforts necessary to comply with Requirements R8 – R10 within the same timeline will result in an unreasonable resource burden that does not provide commensurate reliability benefits.

Likes 0	
Dislikes 0	

Response

Joshua Eason - Joshua Eason On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Joshua Eason

Answer	No
Document Name	
Comment	
ISO-NE does not agree with the January 2021 transition date in the implementation plan. The concern is that the base case used for TPL-007-01 will be obsolete by January 2023 according to the requirement to use a case within the Near-Term Transmission Planning Horizon. Note that the timing for meeting R2 and R4 in TPL-007-1 and the desire to model an as known system as possible (e.g. minimizing the need for case changes as new projects will have been approved and retirements have been announced) has driven ISO-NE to select a study year of 2023. This will create issues when stakeholders review the results and may cause additional study and case building efforts during the first cycle for meeting the new TPL-007-1 reliability standard. ISO-NE proposes that the transition deadline date should be changed from January 2021 to January 2019 or July 2019 so that the base case used for testing with the benchmark waveform according to the known timing for TPL-007-1 can be used for testing the supplemental waveform.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
Consistent with our comments above	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The four-year hardware implementation deadline in R7.3.2 may be impractical, especially if need for a large number of entities to install GIC blocking devices leads to extended lead-times for this equipment. The same issue was thoroughly investigated by the PRC-025 SDT (see the Implementation Plan for this standard), leading to an 84-months deadline, and we recommend that the TPL-007-2 SDT follow this precedent.	
Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
The compliance date for Requirement R9 (if TPL-007-2 becomes effective before January 1, 2021) is too short. We would propose a compliance date of 12 months after the effective date of Reliability Standard TPL-007-2 if it becomes effective before January 1, 2021.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
The implementation plan is not clear on whether the Standard Drafting Team intends on replacing the effective dates of TPL-007-1 for all requirements with the effective date and compliance dates for TPL-007-2 or carrying forward the TPL-007-1 effective dates. Please provide additional language to outline the SDT's intent with the timing between TPL-007-1 effective dates and TPL-007-2 effective dates. Similarly, as the implementation plan is written, under certain situations, the effective dates for performing the assessments for the supplemental event may not necessarily align with the periodicity for performing the assessments for the benchmark event currently required under TPL-007-1, which may create an unnecessary burden for performing assessments on separate cycles.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	

Current implementation dates for requirements 2-6 are January 1, 2021. The implementation plan for TOP-007-2 is confusing. In one bullet it says the effective date is on or before January 1, 2021, and the bullit below it says the effective date is after January 1, 2021.

Likes 0	
Dislikes 0	

Response

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer	No
Document Name	

Comment

As currently written, the implementation plan can actually shorten the current timeframes to become compliant with TPL-007 requirements. It seems that if TPL-007-2 was approved and became effective 7/1/18, then R1, R2, and R5 would also be effective 7/1/18. However, TPL-007-1 R5 isn't supposed to go into effect until 7/1/19. The TPL-007-2 implementation plan should be revised so that entities have at least until the TPL-007-1 effective dates to comply with requirements R1-R7. Tri-State recommends adding language similar to the commonly used "shall become effective on the later of XXXX or the first day of the XX calendar quarter". That would prevent entities from losing time they might have already planned on having to become complaint with R2-R7.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

Current implementation dates for requirements 2-6 are January 1, 2021. The implementation plan for TOP-007-2 is confusing. In one bullet, it says the effective date is on or before January 1, 2021, and the bullet below it says the effective date is after January 1, 2021.

Likes 0	
Dislikes 0	

Response

William Harris - Foundation for Resilient Societies - 8

Answer	No

Document Name	
Comment	
We favor a combined standard for GMD and HEMP events, so that the U.S. electric grid is actually protected against severe solar storms and so it can aid in deterrence, protecton and recovery from both natural and manmade electromagnetic oulse hazards.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP would like clarity on the type of duration (e.g. Calendar Year or Calendar Month) being proposed. This is not explicit in the current draft of the implementation plan.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
TPLTF Discussion: The group agrees with the proposed Implementation Plan for TPL-007-2 and does not see any conflicts with the order by which the phased requirements become effective. However, given the lack of available tools, absence of thermal modeling-related data from transformer manufacturers, and the significant training that will be necessary to properly execute transformer thermal assessments, the group believes that the implementation period for Requirement R10 should be at least 48 months after the standard is approved. This suggested implementation period is consistent with the existing implementation period for Requirement R6 (transformer thermal assessment for benchmark GMD event) and should allow sufficient time for many more transformers that may be observed to exceed the supplemental GMD event screening criterion.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
ISO-NE does not join this response.	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Huitt - Xcel Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
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	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
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 Hydro One, HQ and IESO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Buyce - City Utilities of Springfield, Missouri - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the SDT's efforts to develop a workable Implementation Plan (IP) for TPL-007-2 that reflects the modifications required by FERC's directives in Order No. 830 while attempting to maintain the original five-year phased implementation timeframe established for TPL-007-1. As presently drafted, however, the proposed TPL-007-1 IP attempts to coordinate the existing TPL-007-1 deadlines with the new TPL-007-2 requirements by shortening the compliance dates under the version 2 standard by 18 months in circumstances in which FERC approves the new version before January 1, 2021. This appears roughly coordinated with the May 2018 filing deadline established in Order No. 830.

While Texas RE does not object to this approach, Texas RE notes that the TPL-007-2 IP, as currently drafted, is complex and could produce several unintended consequences as entities interpret their layered compliance obligation timelines. In particular, the proposed IP requires entities to now potentially track two IPs. For instance, the TPL-007-2 IP is drafted such that the enforceable dates for TPL-007-1 R2, presently July 1, 2018, remain under the original IP. While this is a reasonable approach, the SDT should consider explicitly incorporating the deadlines from the TPL-007-1 IP into the TPL-007-2 IP, at least by reference. By taking this approach, the SDT can ensure that responsible entities clearly understand the relevant compliance dates for each Standard requirement and eliminate confusion regarding which compliance dates are subject to revision and which are not.

Such additional clarity may be particularly important in connection with the enforceable dates for TPL-007-2 R5. Under the TPL-007-1 IP, TPL-007-1 R5 is enforceable on January 1, 2019. The proposed TPL-007-2 IP does not address the enforceable date for TPL-007-2 R5. As such, entities are presumably required to comply with TPL-007-2 R5 on the effective date of the Standard. Texas RE presumes that the SDT anticipates that TPL-007-2 will not be effective and enforceable prior to January 1, 2019 given the May 2018 filing deadline, the period for FERC approval, the 60-day period for the FERC order to become final, and the fact that the Standard does not become effective until the first day of the calendar quarter three months after the FERC order is final. However, given the status of this project, it is possible that NERC may wish to submit a revised TPL-007-2 prior to May 2018. For instance, suppose NERC submits a proposal in January 2018 and FERC issues its order in April 2018. The FERC order would become final by July 1, 2018. As such, TPL-007-2 would become enforceable on October 1, 2018. As a result, entities' compliance deadlines would be inadvertently accelerated from January 1, 2019 to October 1, 2018. The SDT should avoid this possibility by clearly delineating within the TPL-007-2 IP which TPL-007-1 enforceable dates remain applicable.

Conversely, the proposed TPL-007-2 IP can be interpreted to extend the compliance deadline for the Benchmark GMD study required under TPL-007 R4 by five years. In particular, the TPL-007-2 IP does not specify an Initial Performance date for the 60-month periodic requirement set forth in TPL-007-2 R4. As such, a plausible reading of the IP is that TPL-007-2 R4 does not become enforceable for 42 months and then, when enforceable, entities have an additional 60 months to complete the Benchmark GMD study under TPL-007-2 R4's periodic performance requirement. This is consistent with NERC's IP guidance in Compliance Application Notice (CAN) No. 12, which states: "[I]n the event the Standard or interpretation is silent with regard to completing a periodic activity, CEAs are to verify that the registered entity has performed the periodic activity within the Standard's timeframe after the enforceable date." (CAN 12 at 1-2). Here, TPL-007-2 R4's enforceable date is set at 42 months from the effective date of the overall Standard. No initial performance date is specified. As such, a responsible entity may reasonably conclude that it has the full 60 month window specified in TPL-007-2 R4 to complete the Benchmark GMD Vulnerability Assessment. This result appears to run counter to the SDT's intent. Texas RE therefore recommends the SDT clearly specify that the initial performance of the TPL-007-2 R4 Benchmark GMD Vulnerability Assessment is due on the enforceable date of that requirement or 42 months from the TPL-007-2 effective date. The same logic can be applied to Requirement R8 as well.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Ginny Beigel, City of Vero Beach, 3; Jeffrey Partington, Keys Energy Services, 4; Joe McKinney, Florida

Municipal Power Agency, 5, 6, 4, 3; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	
Document Name	
Comment	
We would ask that the implementation plan for TPL-007-2 be clearer than it is, especially since the implementation plan for TPL-007-1 is currently underway. We appreciate the efforts of the drafting team in developing the implementation plan for TPL-007-2. However, while it may make perfect sense to the drafting team, it is not clear enough to be used for a compliance standard. Please consider providing some examples, a timeline chart, or providing an acknowledgement of the current dates that entities will be working towards. For example, the selection of the January 2021 date as the "dividing line" between "concurrent implementation" and apparently "non-current" implementation, of the Supplemental and Benchmark events seems to imply the SDT believes one year is sufficient time to add the supplemental event to the benchmark Vulnerability Assessments that are already underway and required to be complete for TPL-007-1 by January of 2022. However, the "more specific" dates offered for Requirements R3, R4 and R8 are 42 months out, which is not January of 2022…so what exactly is intended by "concurrent" and what benefit is gained?	
Likes 0	
Dislikes 0	
Response	
Thomas Rafferty - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee	
Likes 0	

Dislikes 0	
Response	

8. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in proposed TPL-007-2? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs provide your recommendation and explanation.

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

They should be low or medium violation severity levels and risk factors at the most.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	No
Document Name	

Comment

They should be low or medium violaton severity levels and risk factors at the most.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

Since the standard clearly identifies separate GMD Vulnerability Assessments for benchmark and supplemental GMD events, we believe an entity could define separate acceptable System steady state voltage performance criteria for each study. Hence, the Violation Severity Limit for Requirement R3 should be expanded with stair-step severity limits that account for an entity having one criteria for one type of event and not the other.

Likes 0	
Dislikes 0	

Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
Consistent with our comments above	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Colby Bellville - Colby Bellville On Behalf of: Dale Goodwine, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy recommends that the drafting team revisit the order used for the Lower VSL for R8. The first statement in the Lower VSL section regarding the responsible entity completing a supplemental GMD Vulnerability Assessment in more than 60 calendar months, should actually swap positions with the second clause regarding the entity failing to satisfy one of the elements in R8. Having these two clauses swap places, would align with the order of language used in the Moderate, High, and Severe VSL(s).	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
As discussed above, AZPS has identified inconsistency in the treatment of a failure of registered entities to meet the deadline set forth for certain administrative requirements. In some instances, the VSL is simply a binary element and does not increase based on duration of delay or other factors. In other instances, the VSL increases as the duration of the delay increases. Such inconsistency alone is problematic, but, when the administrative nature of and horizon within which these requirements occur are considered, it becomes clear that the VSLs are out of sync with the actual or potential impact that would result from an entity's failure to comply. As these are administrative requirements (provision of documents and/or responses) occurring in the planning horizon, AZPS respectfully asserts that all such VSLs should be considered "low" and should not increase beyond	

that level, which is similar to the treatment in Requirement R8. AZPS recommends that the SDT review not only the new requirements, but the existing requirements to ensure that the VSLs accurately reflect their administrative nature and the fact that the horizon within which these activities are occurring is the Planning Horizon. Specific requirements that should be reviewed for consistency regarding the applicable VSLs include all requirement/sub-requirements with a 90 day timeframe for compliance, e.g., Requirements R4.3, R4.3.1, R5, R7.5, R7.5.1, R8.4, R8.4.1, and R9.2. Again, AZPS respectfully recommends that the SDT treat all 90-day time frame administrative requirements as binary requirements with a low VSL.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

There should be trial period for industry to gain understanding and knowledge of GMD before implementing a standard.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

The VSL for R2 is based on the maintenance of a System Model that is already required by other reliability standards (MOD-032). It is unclear why this is a basis for the VSL for this requirement. The VSL for requirement R2 should pertain to the unique information required by the GIC vulnerability assessments contained in this standard. AEP recommends having only one Severe VSL for not maintaining GIC model data.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	
Comment	

The SPP Standards Review Group agrees with the proposed Implementation Plan for TPL-007-2 and does not see any conflicts with the order by which the phased requirements become effective. However, given the lack of available tools, absence of thermal modeling-related data from transformer manufacturers, and the significant training that will be necessary to properly execute transformer thermal assessments, the group believes that the implementation period for Requirement R10 should be at least 48 months after the standard is approved. This suggested implementation period is consistent with the existing implementation period for Requirement R6 (transformer thermal assessment for benchmark GMD event) and should allow sufficient time for many more transformers that may be observed to exceed the supplemental GMD event screening criterion.

Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	Yes
Document Name	
Comment	

We suggest adding the following High VSL.

"The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator’s planning area for maintaining models and, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s).),

Or

implementing process(es) to obtain GMD measurement data as specified in this standard."

Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC

Answer	Yes
Document Name	
Comment	

We suggest adding the following High VSL.

"The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s),

Or

implementing process(es) to obtain GMD measurement data as specified in this standard."

Likes 0	
Dislikes 0	

Response

Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance

Answer	Yes
Document Name	

Comment

The VRFs should be included in the VSL table within the standard. It isn't clear why they were struck.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Buyce - City Utilities of Springfield, Missouri - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
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 Hydro One, HQ and IESO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
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	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
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	
Joshua Eason - Joshua Eason On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Joshua Eason	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Huitt - Xcel Energy, Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Thomas Rafferty - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes 0	
Dislikes 0	
Response	

9. The SDT believes proposed TPL-007-2 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

While AEP agrees with the scope and direction of the revised standard, the incremental costs and resources required to comply with the proposed revisions may not be commensurate with the resulting impact to the improved reliability of the BES. Adding the Supplemental GMD Vulnerability obligations may substantially increase the resources involved, without a corresponding increase in the reliability of the BES.

Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	

This revision calls for even more assessment of an already rare condition that has historically not been very impactful at lower latitudes. I question the cost-benefit of this standard relative to other grid reliability needs.

Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	

There should be trial period for industry to gain understanding and knowledge of GMD before implementing a standard. Until initial assessments are completed, there's no idea of what a corrective action plan might look like, for example.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1,2 - NPCC	
Answer	No
Document Name	
Comment	
For the Hydro-Quebec power grid it would be already covered by the benchmark event.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	No
Document Name	
Comment	
For the Hydro-Quebec power grid it would be already covered by the benchmark event.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3	
Answer	No
Document Name	
Comment	

Cost effectiveness can't be fully evaluated until more details are provided concerning how mitigation measures and GIC monitoring will be handled. Any required hardware mitigation and GIC monitoring could potentially be costly.

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	No
Document Name	

Comment

Requirement R12 placed responsible entities an additional cost responsibility to collect magnetometer data which would be used just for model validation purpose. Collection of magnetometer data from government agencies or other appropriate agencies directly by NERC would avoid responsible entities' additional cost burden.

Likes 0	
Dislikes 0	

Response

Larisa Loyferman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy disagrees that the proposed TPL-007-2 provides entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. CenterPoint Energy's disagreement is based on the following:

- The proposed Implementation Plan for TPL-007-2 lacks the flexibility to complete the first-of-its-kind modeling and analysis before adding on additional enhanced analysis required to comply with Requirements R8 – R10.
- The prescriptive implementation timelines required by revisions to Requirement R7 do not provide sufficient flexibility for entities to weigh competing system reliability goals in a cost effective manner.
- Adding the Supplemental GMD Vulnerability obligations may substantially increase the resources involved, without a corresponding increase in the reliability of the BES.

Likes 0	
Dislikes 0	

Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
Consistent with our comments above	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
TPL-007-2 continues the error of TPL-007-1 in allowing GOs to only suggest corrective actions (in R6.3), and giving the responsible entity in R7 sole authority to make establish CAPs without having to consult with GOs on the options available or (for competitive markets) demonstrate that all competitors are treated equally. This could be a significant issue, in that CAPs may include directives for, “Installation, modification, retirement or removal,” of multi-million-dollar equipment.	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG is of the opinion that the SDT can improve the cost effectiveness of the standard by combining the Benchmark and the Supplemental GMD events under one definition, thus eliminating duplicate/unnecessary work.	
Likes 0	
Dislikes 0	

Response	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
It is not clear whether the newly established supplemental event will have the effect of increasing the scope of transformers that meet the screening criteria, when compared to the benchmark event and if so, by how much. It does seem possible that an entity which has had no transformers identified as meeting the benchmark event screening criteria could have multiple or all transformers included within the scope of the supplemental event if it is located within the area of a localized enhancement. The technical justification for the supplemental event screening criteria does not substantiate what appears to be a disproportional increase in the intensity of the event compared to the increase in the screening threshold from 75A to 85A. Note that the approach to the thermal assessments required under R6 and R10 are the same, and therefore the proposed supplemental event screening criteria has the ability to impact the financial obligation of the TO and GO.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
Increased costs do not justify the low, if any, reliability benefits.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Increased costs do not justify the low, if any, reliability benefits.	
Likes 0	

Dislikes 0	

Response

William Harris - Foundation for Resilient Societies - 8

Answer	No
Document Name	Foundation for Resilient Societies on NERC Project 2013 081117_Submitted.docx

Comment

The only cost-effective approach for grid protecton is to design for severe GMD hazards and manmade EMP hazards concurrently. This is not a cost effective method, and results in a needlessly vulnerable electric grid. See general comments.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

TPLTF Discussion: The group agrees that the SDT has done a good job of considering cost in time, resources, and personnel commitment in meeting the objectives of the SAR, which were heavily prescribed by FERC Order No. 830. The group may not agree with the perceived benefit to reliability that the additional effort to analyze the supplemental GMD event will yield, but the SDT has proposed a solid means of addressing the FERC directives without relying on tools or methods that do not exist widely in industry today. The group also supports the SDT cost-effective approach to the proposed Requirement R7 which does not mention GIC blocking devices as an integral part of a hardware mitigation. The group remains concerned with the perception that GIC mitigation hardware is presently a viable solution. Given its cost, effects on Protection System design, as well as potential compromises to existing BES reliability, GIC blocking devices may prove undesirable. The flexibility that the SDT has proposed in the development of Corrective Action Plans is workable.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	Yes
Document Name	

Comment

Considering the additional supplemental GMD event analysis doesn't require a CAP to be developed and that data collection is allowed as opposed to having to install new monitoring equipment on the system to acquire the required data, the proposed revisions are flexible and potentially more cost effective for some entities.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

The SPP Standards Review Group agrees that the SDT has done a good job of considering cost in time, resources, and personnel commitment in meeting the objectives of the SAR, which were heavily prescribed by FERC Order No. 830. The group may not agree with the perceived benefit to reliability that the additional effort to analyze the supplemental GMD event will yield, but the SDT has proposed a solid means of addressing the FERC directives without relying on tools or methods that do not exist widely in industry today. We also support the SDT cost-effective approach to the proposed Requirement R7 which does not mention GIC blocking devices as an integral part of a hardware mitigation. The group remains concerned with the perception that GIC mitigation hardware is presently a viable solution. Given its cost, effects on Protection System design, as well as potential compromises to existing BES reliability, GIC blocking devices may prove undesirable. The flexibility that the SDT has proposed in the development of Corrective Action Plans is workable.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gerry Huitt - Xcel Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
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	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1; - Douglas Webb	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, HQ and IESO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Buyce - City Utilities of Springfield, Missouri - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this questions.	
Likes 0	
Dislikes 0	
Response	
Thomas Rafferty - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	

Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee	
Likes 0	
Dislikes 0	
Response	

10. Provide any additional comments for the SDT to consider, if desired.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	
The approved TPL-007-1 and the current draft of TPL-007-2 includes a flowchart diagram in the Application Guides section that provides and overall view of the GMD Vulnerability Assessment process (*and the requirements in TPL-007)*. There has been confusion as to which requirements are represented in the diagram. The NSRF suggest the SDT update this diagram to include annotations that identify the requirements in TPL-007-2. Please see the NSRF example which includes requirements for the benchmark and supplemental assessment.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
None. Thank you.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	
Document Name	
Comment	
Tri-State would like for some additional guidance or examples on what the SDT meant by "hardware" and "non-hardware".	
Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	
Document Name	

Comment
No additional comments.

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	
Document Name	

Comment
The California ISO supports the joint comments of the ISO/RTO Standards Review Committee

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment
1. Add a comma after the “Table 1” reference within Requirement R7, as the lengthy description within the requirement describes the responsible entity and not the development of a CAP. 2. The evidence retention period demonstrating the implementation of a process to obtain GIC monitor and geomagnetic field data, as listed within R11 and R12, is identified as three calendar years. We do not see how this should be different than the evidence retention period identified for the requirements of NERC Reliability Standard TPL-001-4, which is based on the last compliance audit. 3. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response
Scott Downey - Peak Reliability - 1
Answer	
Document Name	
Comment
While Peak supports the SDTs effort, we believe that consideration should be given to making TOPs applicable to the standard as well. Applicable TOPs are required to have operating plans for GMDs to comply with EOP-010 but without direct evaluation of TPL-007 vulnerability assessments, the plans would seem to be incomplete. Peak recognizes the requirement for proposed applicable functions to provide their vulnerability assessments to the RC but believes a more direct coordination role with the TOP should be required.
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 Hydro One, HQ and IESO
Answer	
Document Name	
Comment
On page 11 Table 1 – Note 3 should be also applicable to the row entitled “Supplemental GMD Event – GMD Event with Outages” as it relates to columns “Interruption of Firm Transmission Service Allowed” and “Load Loss Allowed”.
Likes 0	
Dislikes 0	
Response
Thomas Rafferty - Edison International - Southern California Edison Company - 5
Answer	
Document Name	
Comment
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison
Likes 0	
Dislikes 0	

Response

David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	

OPG does not agree with the implementation deadlines:

1) The four years deadline to implement all the hardware mitigation action may provide unfair market advantage to the unaffected/ less affected TOP, GOP due to the time/resources/financial effort involved. Continued operation should be allowed if there is a shortage of hardware, or the lead time to design/procure/implement complete hardware solution exceeds the four years duration.

2) TPL-007-2 should also be applicable as a Functional Entity to Generator Operator (GOP). The implementation of hardware mitigating actions may require the revision of the existing approved GIC mitigation operating procedure instructions (same if the non-hardware mitigation requires operating procedures revisions). The commissioning of the mitigating actions will also require coordination's between the TOP and GOP. GOP should be a stakeholder regarding the configuration impact and determination of affected transformers. Additionally alternative operating configuration may requires design studies involving/requiring GOP support before implementation.

3) The two years deadline to implement all the non-hardware solution may provide unfair market advantage to the unaffected/less affected TOP, GOP, as the implementation for a large scale TOP, GOP will take more time, resources/financial effort and may require commissioning and studies.

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	

Table 1 in the standard, under the "Steady State:" heading, part a, the sentence should be expanded as follows: "Voltage collapse, Cascading, and uncontrolled islanding shall not occur for the Benchmark GMD event, but can occur for the Supplemental GMD event subject to additional analysis specified in R8.3.

Also, verbiage in R8.3 should be expanded to include references to Voltage collapse and uncontrolled islanding

Likes 0	
Dislikes 0	

Response

Colby Bellville - Colby Bellville On Behalf of: Dale Goodwine, Duke Energy , 6, 5, 3, 1; - Colby Bellville, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy requests further clarification regarding the 90 calendar day timeframe outlined in R4. The current language states that the Responsible Entity must provide its benchmark GMD Vulnerability Assessment to the RC, adjacent PC, and adjacent TP within 90 calendar days of completion. Clarification is needed as to what date the term “completion” is referring to. Many entities may have 3rd parties conduct these studies, and in doing so, the Responsible Entity will review the study and make corrections where necessary. Is the completion date referred to in the requirement referring to the date the initial study (by the 3rd party) is completed, or is it referring to the date that the Responsible Entity has completed its internal review and obtained signoff by management? If the drafting team’s intent was for the completion date to refer to the date that the initial study was performed, we cannot agree with the 90 calendar day timeframe. Additional time would be needed for the Responsible Entity to perform its review of the 3rd party study, and obtain management signoff.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Although not necessarily in the scope of this project, Texas RE noticed a few other things.	

- There could be some clarity in which earth models are supposed to be used. The “earth model” physiographic regional maps supplied and referenced are not detailed enough to indicate the physical locations of the regional conductivity map boundaries. This lack of detail will be a source of confusion if a transformer is located near a conductivity boundary. What earth model value does the responsible entity use? If there are 3 regional conductivity areas in one responsible entity’s planning area, what earth model value does the responsible entity use?

- Texas RE is concerned the lack of a timeframe to provide GIC flow information in Requirements R5 and R9 could lead to an entity not providing GIC flow information when that information is necessary for the thermal impact assessments. Texas RE requests the SDT add a timeframe for providing the data.

- Although R1 states the PCs and TPs will identify the individual and joint responsibilities for maintaining models and performing the studies needed to complete the benchmark and supplemental GMD Vulnerability Assessments, there does not appear to be any coordination while actually performing these tasks. Texas RE is concerned this could lead to TPs each doing their own studies and coming to different conclusions, which would not allow entities to recognize vulnerabilities effectively. Texas RE recommends the PC do an overall assessment every 60 calendar months.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3

Answer	
Document Name	

Comment

no

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
The approved TPL-007-1 and the current draft of TPL-007-2 includes a flowchart diagram in the Application Guides section that provides and overall view of the GMD Vulnerability Assessment process (*and the requirements in TPL-007)*. There has been confusion as to which requirements are represented in the diagram. The NSRF suggest the SDT update this diagram to include annotations that identify the requirements in TPL-007-2. Please see example below which includes requirements for the benchmark and supplemental assessment.	
Likes 1	Darnez Gresham, N/A, Gresham Darnez
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
“PacifiCorp requests the drafting team add to the white paper links to the resources where geomagnetic field data from the magnetometers inside NERC footprint is publicly available.”	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
Please refer to comments submitted by Robert Blackney on behalf of Southern California Edison.	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

AZPS is concerned that the proposed revisions to Requirement R1 to add references to the need for processes related to obtaining GMD data is inconsistent with respect to how such data is defined in later requirements, e.g., Requirements R11 and R12, and creates confusion relative to the need and use of such data and to which data-related actions and requirements Requirement R1 applies. For these reasons, AZPS proposes the following revisions to ensure clarity:

R1. 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**, including the data-related processes identified in Requirements R9, R11, and R12 in this standard, and,** performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	
Document Name	

Comment

The standard doesn't talk about how to develop equivalents of neighbouring systems and what assumptions to make. Is there only a GMD event impacting your assessment area and none in neighbouring areas?

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	
Document Name	

Comment

On page 11 Table 1 – Note 3 should be also applicable to the row entitled “Supplemental GMD Event – GMD Event with Outages” as it relates to columns “Interruption of Firm Transmission Service Allowed” and “Load Loss Allowed”.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

The language used for Measure M5 was adjusted incorrectly as it currently states “… *that it has provided the maximum effective* ***benchmark*** *GIC value to the Transmission Owner and Generator…..* “. This is an incorrect statement and should instead state “*…that it has provided the maximum effective GIC value* ***under the benchmark event*** *to the Transmission Owner and Generator…..”*

While AEP supports the overall effort of the drafting team, AEP has chosen to vote "no" driven by the lack of clarity related to the potential duplication of efforts related to assets which are in-scope for both the benchmark and supplemental assessments. Similarly, AEP is concerned by the overall burden associated with having a secondary suite of “parallel requirements” to accommodate the supplemental assessment.

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer	
Document Name	

Comment

Comments:

1. Parallels between R4 and R8:

It appears that the standard is now requiring applicable entities to perform two GMD Vulnerability assessments (benchmark and supplemental), either at the same time, or within 5 years or less of each other. This seems to be duplicative and should be characterized as a sensitivity to the benchmark and done at the same time if required or be performed as part of “subsequent” assessments. Also on that note, the supplemental assessment has an

additional requirement (R8.3) to determine if Cascading occurs, where the benchmark assessment does not. Cascading is often required to be determined via stability analysis which is outside the scope of TPL-007-2 because the standard as written only requires steady state/load flow analysis. Can the SDT please elaborate on this shift in requiring entities to evaluate Cascading in the supplemental assessment and not in the benchmark assessment, as well as elaborate on the need to evaluate Cascading as a whole?

Also, the requirement of having to provide the completed assessment to the applicable entities, rather than just making it available (as originally drafted), is not providing any reliability benefit other than paperwork for the entities, I thought Paragraph 81 was initiated to get away from such requirements and here we are putting them right back in.

1. R7.3.1,7.3.2:

What does the SDT envision as a “non-hardware” mitigation vs. a hardware mitigation?

1. R4, R8

Why does the SDT feel it necessary to add the phrase “at least” in the requirements associated with subsequent GMD assessments? The existing language, without the insert, does not preclude an entity from performing an assessment sooner than the 60 calendar months if the entity determines it necessary, the insert of “at least” provides no added benefit or clarity to the existing language.

1. Applicable Facilities:

Has the SDT given any consideration to clarifying the applicable Facilities within TPL-007-2? The standard is only applicable to PCs, TOs, and GOs; however, there are transformers that are wye-grounded on the high-voltage terminals, operated at greater than 200 kV but are not owned by registered TOs or have been excluded from the BES, pursuant the BES Definition. How does the SDT plan to address those? For example, a GO can provide their respective PC with GSU information for the GMD model; however, their auxiliary transformer(s) which are connected on the high-side at 200 kV or greater and are wye-grounded are not considered BES Facilities and therefore are not required to be provided to the PC as part of their evaluation, even though the unit auxiliary transformers have the potential of tripping the entire plant.

1. Cost Study

Seminole requests the SDT perform a CEAP (Cost Effective Analysis Process) for this Standard. TPL-007 is a great candidate as the costs of all of the studies is substantial and the frequency of an event causing catastrophic consequences is low.

2. FRCC Specific TPL-007-2

Seminole requests that the SDT develop an initial low cost study that would allow for entities in the very far south to be excluded from performing further compliance measures. In the alternative, Seminole requests the SDT to note that the SDT is open to the idea of reduced requirement FRCC-specific TPL-007-2.

1. 7.3.1

Change the time value to 24 months instead of 2 years to stay consistent. Same with 7.3.2.

1. R11 Note

The Note for R11 states that the data collected via magnetometers and GIC monitoring is necessary for “situational awareness”. Does the SDT believe that the data collected for situational awareness could classify this collection equipment as BES Cyber Assets if system operators make decisions based off of this equipment within 15 minutes?

Likes 0	
Dislikes 0	

Response

Comments of the Foundation for Resilient Societies on **NERC Project 2013-03 Geomagnetic Disturbance Mitigation, Transmission System Planned Performance for Geomagnetic Disturbance Events, Draft of TPL-007-2.**

We provide brief comments on the Draft Standard, Draft Implementation Plan, and Research Work Plan of NERC.

Draft **Reliability Standard TPL-007-2** is based on modeling that is substantially divorced from the empirical evidence of bulk power system equipment susceptibility to damage or total losses during moderate geomagnetic disturbances during just the past three decades.

NERC's GMD Vulnerability Assessment process lacks scientific rigor. A rigorous standard would include:

> Collection of all known or likely bulk power system equipment damage or loss during all three known classes of geomagnetic disturbance: (1) **coronal mass ejections (CMEs)** , upon which NERC has concentrated; (2) more extended duration but less intense **coronal hole proton streams (CHs),** associated with a substantially larger set of EHV transformer fires and explosions during the past three decades; and (3) **sudden commencement** or **sudden reversal GMDs**¸ such as occurred at Seabrook Station between November 8 and 10, 1998, with resulting meltdown of lower voltage windings in the Phase A 345 kV transformer.

Transformer thermal impact assessments, if performed only if the maximum effective geomagnetically induced current (GIC) in the transformer is equal or greater than 75 amps per phase for the benchmark GMD event, and 85 amps per phase for the supplemental GMD event, are imprudent and needlessly risky, for a class of equipment with replacement times measured in months or years.

Idaho National Laboratory suspended injection of quasi-DC currents into a 138 kV transformer during tests with and without attachment of a neutral ground blocker in year 2013. Why was it necessary for INL test managers to suspend the DC current injections at a level of 22 amps per phase, to avert transmission system damage, if the standard's threshold is "prudently" set at 75 amps per phase?

What is needed is a more comprehensive set of GMD classes of hazard, a sharing of data on equipment losses since at least year 1989, not year 2013, improved modeling, and widespread testing of vulnerable BES equipment both under load and to destruction. Geomagnetically Induced Current (GIC) data should be retained indefinitely, not for the 3 years specified in the draft standard, because the return period for severe solar storms can be in excess of 100 years.

NERC claims that "the respective screening criteria are **conservative**…" (NERC Thermal Screening Criterion White Paper, 2017). We dispute this claim and see no scientific foundation for it. As a result of these deficiencies, the bulk electric system remains highly vulnerable to natural occurring geomagnetic disturbances, and more powerful high altitude electromagnetic pulse (EMP) hazards that are manmade.

Respectfully submitted by:

William R. Harris

SPP TPLTF Review of TPL-007-2 Comment Questions published by Project 2013-03 (Geomagnetic Disturbance Mitigation)

In July 2017, the Project 2013-03 Standard Drafting Team (SDT) released an unofficial comment form to allow the industry to provide feedback on the proposed TPL-007-2 – Transmission System Planned Performance for Geomagnetic Disturbance Events standard. It is noted that the industry comment period is brief and all comments must be submitted by Friday, August 11, 2017. Given that the SPP TPLTF has been actively developing guidance and processes for SPP and its members to address the approved TPL-007-1 standard, this open comment period offered an opportunity for the TPLTF to collectively review the proposed standard. Further, the TPLTF assessed the TPL-007-2 official comment questionnaire and discussed potential industry responses. The following represents a summary of the informal discussion conducted by the TPLTF and is provided to add value to those SPP members who choose to submit comments during the open period. The information given here should be considered non-binding and is intended to supplement independent reviews of the proposed TPL-007-2, thereby adding the value of a TPLTF perspective.

If you have any questions, please contact the SPP TPLTF secretary Scott Jordan (SPP staff, sjordan@spp.org) or the SPP TPLTF chairperson Chris Colson (WAPA-UGPR, colson@wapa.gov).

General comment: Upon the TPLTF review of FERC Order No. 830, released in September 2016, it is clear that the FERC directives are very prescriptive. The group felt that there was little leeway offered the Project 2013-03 in drafting the proposed TPL-007-2 changes. Knowing this, the TPLTF review focused on the SDT approach to meeting the directives of FERC Order No. 830 and its impact upon the SPP Planning Coordinator, as well as SPP member Transmission Planners, Transmission Owners, and Generator Owners. The TPLTF took particular care to focus upon the draft requirements of TPL-007-2 and attempted to omit any discussion of the FERC directives themselves, given that they are established in Order No. 830.

Questions from the TPL-007-2 Comment Form

1. The SDT developed proposed Requirements R8 – R10 and the supplemental GMD event to address FERC concerns with the benchmark GMD event used in GMD Vulnerability Assessments. (Order No. 830 P.44, P.47-49, P.65). The requirements will obligate responsible entities to perform a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for potential impacts of localized peak geoelectric fields. Do you agree with the proposed requirements? If you do not agree, or if

you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

TPLTF Discussion: The group agrees with the SDT approach to addressing FERC Order No. 830 Paragraph 44. In effect, the SDT has specified an extreme value for geoelectric field, called the supplemental GMD event, intended to represent a locally-enhanced geoelectric field experienced by a limited geographic area. In other words, the SDT has proposed a means by which Planning Coordinators and Transmission Planners can approximate a non-geospatially-averaged peak geoelectric field, thus meeting the intent of the FERC Order No. 830 directive. While determining peak geoelectric field amplitudes not based solely on spatially-averaged data is a significant challenge to meeting the FERC directive, primarily because of the lack of North American data, as well as analytical tools available to Planning Coordinators and Transmission Planners, the group believes the SDT has found a workable approach.

The group would like to note that it will be non-trivial to apply the localized peak geoelectric field in the supplemental GMD event to a spatially-limited area, described in the proposed TPL-007-2 Attachment 1, given available software tools and available personnel resources. This will be especially pronounced for Planning Coordinators and Transmission Planners with large geographical footprints. Many planning entities will be forced to apply the supplemental peak geoelectric field over their entire area, in effect simply studying a higher magnitude benchmark GMD event. While the group believes this is prominently conservative, as stated above, we understand and support the SDT approach to this directive. It is likewise noted that the definition of a spatially-limited area is absent in the materials published by the SDT, but this vagary supports better analytical flexibility for Planning Coordinators and Transmission Planners and should not be defined in the draft standard.

2. The SDT developed the *Supplemental GMD Event Description* white paper to provide technical justification for the supplemental GMD event. The purpose of the supplemental GMD event description is to provide a defined event for assessing system performance for a GMD event which includes a local enhancement of the geomagnetic field. Do you agree with the proposed supplemental GMD event and the description in the white paper? If you do not agree, or if you agree but have comments or suggestions for the supplemental GMD event and the description in the white paper provide your recommendation and explanation.

TPLTF Discussion: The group recognizes that there are multiple methods to approach revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data (FERC Order No. 830 Paragraph 44). However, given a wide diversity in available data, analytical tools, and personnel expertise, the group believes that the SDT has found a practical approach to meeting the objective of the FERC directive. Moreover, the *Supplemental GMD Event Description* white paper presents a reasoned justification for the use of the geoelectric field amplitude of 12 V/km.

The group recommends that the SDT consider a less ambiguous name for the Supplemental GMD Event; the group believes *Extreme Value GMD Event* would be more appropriate for the following reasons:

a. Implies a closer relationship to the extreme events of TPL-001-4 for which Planning Coordinators and Transmission Planners are familiar.

b. Is better aligned with the extreme value statistical analysis that was conducted to produce the subject reference peak geoelectric field amplitude.

c. Indicates a measure of how rare the extreme value for the 1-in-100 year peak geoelectric field amplitude may be, based upon the 95% confidence interval of the extreme value.

While the group agrees that the application of extreme value statistical methods presented in the *Supplemental GMD Event Description* white paper is sound, three clarifying statements should be made in the white paper. Firstly, in short, the group agrees that by using the 23 years of daily maximum geoelectric field amplitudes from IMAGE magnetometers, a proxy of higher magnitude events can be characterized. It is noted that the southernmost magnetometer in the IMAGE chain resides in Suwałki, Poland at 54.01°N, whose geographic latitude places it roughly 500 miles north of Quebec. Given that geoelectric field is highly correlated with geomagnetic latitude rather than geographic latitude, the IMAGE data should still be referred to as a loose approximation for estimated North American geoelectric field magnitudes (Suwałki, Poland geomagnetic dipole latitude 52°N, Quebec geomagnetic dipole latitude 56°N). In other words, the group believes it is appropriate to qualify that the extreme value analysis performed in the white paper is based upon maximum data points obtained from an array of northern geomagnetically-biased latitudes, further inflated by using the high earth conductivity of Quebec. Secondly, it is well known that coastal geological conditions can lead to locally-enhanced geoelectric fields, not observed in regions more distant from the coast. Given that nearly all of the IMAGE chain magnetometers reside within 100 miles of the northern Atlantic Ocean or Baltic Sea coasts, it is reasonable to conclude that the geoelectric field amplitudes derived from the corresponding IMAGE data may have suffered from geoelectric field enhancement along conductivity boundaries. With respect to serving as a proxy for mainland North American peak geoelectric field amplitude, the SDT should consider further qualifying the appropriateness of the IMAGE data which served as the foundation of the extreme value analysis. Finally, the group agrees that the use of more resolute point over threshold (POT) methods was indicated over generalized extreme value (GEV). For clarity, however, it should be emphasized that the geoelectric field amplitude of 12 V/km represents the *extreme value* of the upper limit of the 95 percent confidence interval for a 100-year return interval. In other words, the statistical significance of the extreme value confidence interval is not equivalent to the statistic expressed by the confidence interval for the data set consisting of 23 years of all sampled geoelectric field amplitudes (not shown). Each of these considerations, if addressed, can strengthen the conclusions of the white paper by emphasizing its conservative approach.

3. The SDT established an 85 A per phase screening criterion for determining which power transformers are required to be assessed for thermal impacts from a supplemental GMD event in Requirement R10.

Justification for this threshold is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment* white paper. Do you agree with the proposed 85 A per phase screening criterion and the technical justification for this criterion that has been added to the white paper? If you do not agree, or if you agree but have comments or suggestions for the screening criterion and revisions to the white paper provide your recommendation and explanation.

TPLTF Discussion: Given the use of the 12 V/km geoelectric field amplitude for the supplemental GMD event, the group agrees with the proposed 85 Amp threshold justified in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper. The group suggests that the proposed change on page 11 of the white paper stating "because the supplemental waveform has a sharper peak, the peak metallic hot spot temperatures associated with the supplemental waveform are slightly lower than those associated with the benchmark waveform" be clarified. In other words, this statement is counterintuitive given that the increased supplemental time-series waveform peak value implies higher GIC flows that, when experienced by a transformer will lead potentially higher metallic hot spot temperatures. A suggested approach to better communicate this point is as follows:

Given that GICs are proportional to the time-varying electric field, according to:

$$GIC(t) = |E(t)| \cdot \left[GIC_{Easterly} \sin\varphi(t) + GIC_{Northerly} \cos\varphi(t)\right] \quad (1)$$

The joule heating effect in transformers is proportional to the time-varying GIC, as:

$$\frac{dQ}{dt} \propto GIC(t)^2, \ \ where\ P(t) = I(t)^2 R,\ Q = \int P(t)dt \quad (2)$$

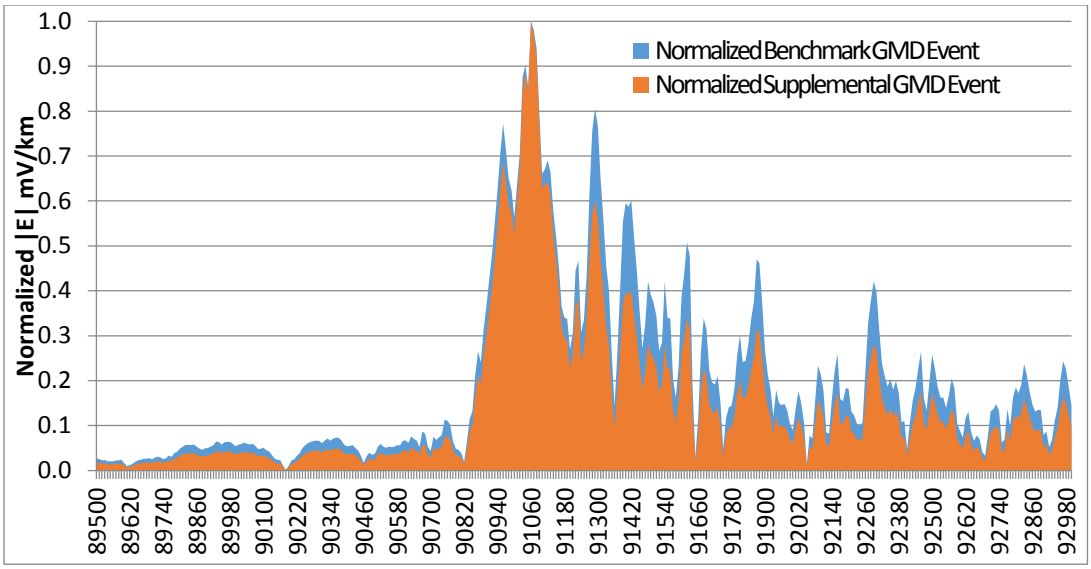
It follows that the transformer metallic hot spot temperature is proportional to the time-varying GIC, as:

$$T_F \propto \int GIC(t)\ dt,\ given\ T_0 \qquad where\ \frac{dQ}{dt} = c_P m \frac{dT}{dt} \quad (3)$$

Therefore, the corresponding proportion that relates the transformer metallic hot spot temperature to time-varying geoelectric field amplitude is expressed by:

$$T_{metallic\ hot\ spot} \propto \int E(t)\ dt \quad (4)$$

The figure below shows the benchmark GMD and supplemental GMD event waveforms normalized to their respective geoelectric field peak amplitudes. By portraying the two events in this manner, it is evident that the relationship given in (4) leads to a proxy heating quantity for the benchmark GMD event approximately 32% more than the supplemental GMD event. Even though the peak GIC induced by the supplemental GMD is higher than the benchmark, the total heating is less (integral).



In other words, if the peak transformer GIC screening threshold were 75 A/phase for both events, the transformer suffering a supplemental GMD event would experience less overall heating; the aggregated effects of the Supplemental geoelectric field "intensity" is not sustained. Thus, the screening threshold for supplemental GMD event transformer GIC is established at a slightly higher, but conservative, 85A/phase.

4. The SDT revised the *Transformer Thermal Impact Assessment* white paper to include the supplemental GMD event. Do you agree with the revisions to the white paper? If you do not agree, or if you agree but have comments or suggestions on the revisions to the white paper provide your recommendation and explanation.

TPLTF Discussion: The group agrees with the changes in the *Transformer Thermal Impact Assessment* white paper, with the exception of the explanation provided for Table 2 on page 5. Similar to the comment made regarding the counterintuitive language in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper, it is not clear why metallic hot spot temperatures are reduced for the supplemental GMD event for the same effective GIC and transformer bulk oil temperature. Additional clarity on this point would improve the ability of applicable entities to rely upon the reference data provided. The group recommends adding white paper language similar to that suggested in Question Q3.

The group would like to highlight that the study of supplemental GMD event conditions may cause a significantly larger number of transformers to be added for assessed by Transmission Owners and Generator Owners. Given that the analytical tools and modeling software available for this type of analysis are limited, as well as the fact that most manufacturers supplying power transformers to U.S. customers do not include data necessary to complete detailed thermal modeling with transformer test reports, the additional effort to satisfy the supplemental GMD event analysis will be arduous. The group recommends that the SDT consider the reality that these tools are merely in their infancy across the industry, and

additional time to develop, deploy, and train on them should be included in the TPL-007-2 implementation plan to complete transformer thermal assessments for the supplemental GMD event.

5. The SDT developed proposed Requirement R7 to address FERC directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments (P. 101, 102). Do you agree with the proposed requirement? If you do not agree, or if you agree but have comments or suggestions for the proposed requirement provide your recommendation and explanation.

TPLTF Discussion: Given the specificity of the Paragraphs 101 and 102 directives of FERC Order No. 830 Paragraph 44, the group believes that the SDT had little flexibility when developing the proposed language of Requirement R7. The group agrees with the proposed Requirement R7, as presented. The group would like to reiterate the suggestion that the Supplemental GMD Event nomenclature be changed to Extreme Value GMD Event, as explained in the group's discussion of Question Q2.

6. The SDT developed Requirements R11 and R12 to address FERC directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data (P. 88; P. 90-92). Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

TPLTF Discussion: Despite the added cost to implement additional monitoring and data collection, the group agrees that the SDT developed a reasonable approach to the FERC directives in Order No. 830 Paragraph 88.

7. Do you agree with the proposed Implementation Plan for TPL-007-2? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

TPLTF Discussion: The group agrees with the proposed Implementation Plan for TPL-007-2 and does not see any conflicts with the order by which the phased requirements become effective. However, given the lack of available tools, absence of thermal modeling-related data from transformer manufacturers, and the significant training that will be necessary to properly execute transformer thermal assessments, the group believes that the implementation period for Requirement R10 should be at least 48 months after the standard is approved. This suggested implementation period is consistent with the existing implementation period for Requirement R6 (transformer thermal assessment for benchmark GMD event) and should allow sufficient time for many more transformers that may be observed to exceed the supplemental GMD event screening criterion.

8. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirements in proposed TPL-007-2? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs provide your recommendation and explanation.

TPLTF Discussion: The group agrees with the apportionment of the VRFs and VSLs.

9. The SDT believes proposed TPL-007-2 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

TPLTF Discussion: The group agrees that the SDT has done a good job of considering cost in time, resources, and personnel commitment in meeting the objectives of the SAR, which were heavily prescribed by FERC Order No. 830. The group may not agree with the perceived benefit to reliability that the additional effort to analyze the supplemental GMD event will yield, but the SDT has proposed a solid means of addressing the FERC directives without relying on tools or methods that do not exist widely in industry today. The group also supports the SDT cost-effective approach to the proposed Requirement R7 which does not mention GIC blocking devices as an integral part of a hardware mitigation. The group remains concerned with the perception that GIC mitigation hardware is presently a viable solution. Given its cost, effects on Protection System design, as well as potential compromises to existing BES reliability, GIC blocking devices may prove undesirable. The flexibility that the SDT has proposed in the development of Corrective Action Plans is workable.

10. Provide any additional comments for the SDT to consider, if desired.

TPLTF Discussion: None additional.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2013-03 Geomagnetic Disturbance Mitigation

DO NOT use this form for submitting comments. Use the electronic form to submit comments on proposed **TPL-007-2 – Transmission System Planned Performance for Geomagnetic Disturbance Events**. The electronic comment form must be completed by **8:00 p.m. Eastern, Friday, August 11, 2017**.

Documents and information about this project are available on the project page. If you have any questions, contact Standards Developer, Mark Olson (via email), or at (404) 446-9760.

Background Information

On September 22, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 830 approving Reliability Standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events. In the order, FERC directed NERC to develop certain modifications to the Standard, including:

- Modify the benchmark geomagnetic disturbance (GMD) event definition used for GMD Vulnerability Assessments;
- Make related modifications to requirements pertaining to transformer thermal impact assessments;
- Require collection of GMD-related data; and
- Require deadlines for Corrective Action Plans (CAPs) and GMD mitigating actions.

FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018.

The standard drafting team (SDT) has developed proposed TPL-007-2 to address the above directives.

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. The SDT developed proposed **Requirements R8 – R10** and the supplemental GMD event to address FERC concerns with the benchmark GMD event used in GMD Vulnerability Assessments. (Order No. 830 P.44, P.47-49, P.65). The requirements will obligate responsible entities to perform a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for potential impacts of localized peak geoelectric fields. Do you agree with the proposed requirements? If you do not agree, or if

you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

☒ Yes
☐ No
Comments:

2. The SDT developed the ***Supplemental GMD Event Description*** **white paper** to provide technical justification for the supplemental GMD event. The purpose of the supplemental GMD event description is to provide a defined event for assessing system performance for a GMD event which includes a local enhancement of the geomagnetic field. Do you agree with the proposed supplemental GMD event and the description in the white paper? If you do not agree, or if you agree but have comments or suggestions for the supplemental GMD event and the description in the white paper provide your recommendation and explanation.

☒ Yes
☐ No
Comments:

3. The SDT established an 85 A per phase screening criterion for determining which power transformers are required to be assessed for thermal impacts from a supplemental GMD event in Requirement R10. Justification for this threshold is provided in the revised ***Screening Criterion for Transformer Thermal Impact Assessment*** white paper. Do you agree with the proposed 85 A per phase screening criterion and the technical justification for this criterion that has been added to the white paper? If you do not agree, or if you agree but have comments or suggestions for the screening criterion and revisions to the white paper provide your recommendation and explanation.

☒ Yes
☐ No
Comments: "Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event" from the screening criterion document provides a useful visual, can the drafting team additionally provide a similar chart and the data for the supplemental GMD event?

4. The SDT revised the ***Transformer Thermal Impact Assessment*** **white paper** to include the supplemental GMD event. Do you agree with the revisions to the white paper? If you do not agree, or if you agree but

have comments or suggestions on the revisions to the white paper provide your recommendation and explanation.

☒ Yes
☐ No
Comments: Table 1 and 2 are useful to show the differences between the benchmark event and the supplemental, but some of the figures are not clear which GMD event was used to generate the gic(t) time series. Can some additional language be added to clarify the GMD event of the figures in this document?
Also, there was some inconsistency in axis labels and units between the various figures, which makes it difficult to draw conclusions when comparing the charts. For example A/phase versus Amps, minutes versus hours for the time scale. Can these charts be updated with uniform axis labels and units for comparative purposes?

5. The SDT developed proposed **Requirement R7** to address FERC directives in Order No. 830 for establishing **Corrective Action Plan (CAP) deadlines** associated with GMD Vulnerability Assessments (P. 101, 102). Do you agree with the proposed requirement? If you do not agree, or if you agree but have comments or suggestions for the proposed requirement provide your recommendation and explanation.

☒ Yes
☐ No
Comments:

6. The SDT developed Requirements **R11 and R12** to address FERC directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data (P. 88; P. 90-92). Do you agree with the proposed requirements? If you do not agree, or if you agree but have comments or suggestions for the proposed requirements provide your recommendation and explanation.

☒ Yes
☐ No
Comments: Neutral current measurements are not sufficient to benchmark autotransformer performance in a GMD event; TOs would need at least two out of three leg measurements to do this. Additionally, the proxy magnetometer data leaves flexibility for the TO, but may not prove to be effective for benchmarking without other additional considerations. While the intent of the R11 requirement is to benchmark the model, without accurate magnetometer installations in each TOs footprint, it may be difficult to do so; particularly where no nearby proxy data can be leveraged. Can the drafting team consider increasing R11 further and require TOs to either install measuring devices in their area, and/or to prove the accuracy of the proxy data? Also, can the drafting team consider a requirement for additional measurements on autotransformers?

7. Do you agree with the proposed **Implementation Plan for TPL-007-2**? If you do not agree, or if you agree but have comments or suggestions for the Implementation Plan provide your recommendation and explanation.

☒ Yes
☐ No
Comments:

8. Do you agree with the **Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs)** for the requirements in proposed TPL-007-2? If you do not agree, or if you agree but have comments or suggestions for the VRFs and VSLs provide your recommendation and explanation.

☒ Yes
☐ No
Comments:

9. The SDT believes proposed TPL-007-2 provide entities with flexibility to meet the reliability objectives in the project Standards Authorization Request (SAR) in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable additional cost effective approaches to meet the reliability objectives, please provide your recommendation and, if appropriate, technical justification.

☒ Yes
☐ No
Comments:

10. Provide any additional comments for the SDT to consider, if desired.
Comments: