Individual or group. (74 Responses)
Name (50 Responses)
Organization (50 Responses)
Group Name (24 Responses)
Lead Contact (24 Responses)
Question 1 (53 Responses)
Question 1 Comments (64 Responses)
Question 2 (50 Responses)
Question 2 Comments (64 Responses)
Question 3 (51 Responses)
Question 3 Comments (64 Responses)
Question 4 (54 Responses)
Question 4 Comments (64 Responses)
Question 5 (48 Responses)
Question 5 Comments (64 Responses)
Question 6 (51 Responses)
Question 6 Comments (64 Responses)
Question 7 (58 Responses)
Question 7 Comments (64 Responses)

Individual
Frederick R Plett
Massachusetts Attorney General
Yes
Yes
Yes
Yes
Yes
No
R3 points to Table 1 Steady State Planning Events. Footnote 4 of that Table states "Load loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance." For an event that occurs with a 100 year severity level, load loss should absolutely be allowed to be the primary method of achieving required performance. Otherwise this requirement insists on expenditures of dollars of some unspecified amount for unspecified measures that have extremely low value that could be better implemented elsewhere.
No
Individual
John Bee on behalf of Exelon and its affiliates
Exelon
Yes
Yes
While the proposed Benchmark event appears to be technically justified and provides the necessary basis for conducting assessments, the level of detail suggested for conducting transformer thermal

assessments seems overly complicated and cumbersome. Recommend that a streamlined methodology be developed, or defined by the PC or TP, to evaluate transformer thermal impacts based on high-level characteristics of the Benchmark event and the analysis performed by the PC or TP. Any real event will likely share general characteristics with the Benchmark event, but will be completely different in terms of its actual signature. A more straightforward evaluation methodology would be more efficient and possibly just as effective as detailed analysis for each transformer based on a specific signature. The Thermal Assessment whitepaper describes a technique that consists of selecting a GIC pulse representative of the GIC peak. Could one (or more) pulses be defined with a magnitude and duration that are representative of the “worst” part of the Benchmark event and used as a standard test for R6? It seems this would not be much different than the simplified analysis described in the whitepaper, except that a uniform test would be defined rather than allowing each entity to choose what they believe a representative GIC pulses may be. Additionally choosing a worst case could allow for creating specifications for new transformers to assure that they can withstand the event and allow for establishing a uniform test pulse so manufacturers could more effectively perform testing and provide data which will ultimately be requested from all of their customers once the standard goen into effect.
Yes
No
Exelon greatly appreciates the time and effort the SDT has put into this draft but cannot support the draft based on the time frame cited in this requirement. R6.4 states that the thermal assessment should be performed within 12 months after receiving the GIC flow information. Considering the potential number of transformers in scope for Exelon and the data that would need to be requested of the transformer vendors, 12 months is not enough time to perform the thermal assessments. Recommend changing R6.4 to read. Be performed and provided to the responsible entities as determined in Requirement R1 within 24 calendar months of receiving GIC flow information specified in Requirement R5.
Yes
Yes
It would seem that once mitigation actions take place the GMD assessment would need to be re-run to determine the effectiveness of the mitigation, the draft standard doesn’t address analysis of the mitigation actions. Recommend adding a requirement or clairifying text to address the necessary time to perform this iteration. Duration of GIC current application is not provided in a straight forward manner. It would be beneficial if some time limit is assigned with GIC value being provided by the PC / TP to aid in conducting the thermal assessment. Would it be appropriate to assume the GIC present on a transformer be present for maximum of 30 minutes for thermal assessment purposes? Furthermore, can this current be assumed a pure DC current? The document “Screening Criterion for Transformer Thermal Impact Assessment” under Justification references IEEE C57.91-2001 standard. The reference standard should be latest issue of 2011. All of the proposed Transformer Thermal Impact Assessment methods require some involvement by the manufacturer to determine the hot spot thermal transfer functions in order to calculate capability curves. What obligation is the transformer manufacturer under to provide this data, assuming that it is even available? This is especially difficult considering the number of large power transformer manufacturers that are no longer in business. Void of this information, the suggestion is to perform measurements. How would these measurements be performed on an existing transformer already installed in the field? NERC also suggests using generic published values published in Reference 4 “Simulation of Transformer Hotspot Heating due to GIC” IEEE Transactions paper. On what basis is NERC suggesting this as a technically viable alternative? The TPL-007-1 Common Questions and Responses document dated, June 12, 2014, includes a question “Why are generator impacts not specifically addressed in TPL-007?” and provides the following response: “While technical literature has been written on potential generator impacts due to GIC, planning tools are not available to conduct the necessary detailed harmonic analysis. The standard reflects the currently available tools and techniques. The standard does not preclude an entity from conducting additional studies”. Using similar logic, if data or tools are not available to accurately assess thermal impacts on existing

transformers for which data is not available, should these not be exempt from assessments? Lack of data will likely require use of overly-conservative assumptions, effectively “penalizing” legacy equipment. It would appear that this position could be applied when the manufacture data and the necessary tools are unavailable to assess the thermal impacts on existing transformers?
Group
PacifiCorp
Sandra Shaffer
No
PacifiCorp agrees that this model more closely aligns with the GMD Vulnerability process, but the open issues about scope of transformers (Q-7), level of loading (Q-3) and the iterative language in the standard, indicate to PacifiCorp that these issues must be addressed before a decision can be made whether or not to support the current flow chart.
No
Please refer to PacifiCorp’s responses to Q-3 and Q-7. While Attachment 1 is a well written document, it does not provide enough detail to adequately address the multiple variables in a multi-state area for large entities that (1) are not currently familiar with the technical applications of the soon-to-be-developed software and (2) cover a large geographic area. “Additional guidance” concerning applying the benchmark event is now in Appendix 1 of proposed TPL-007-1. Specifically, Appendix 1 now addresses how a planning entity with a large geographic can handle scaling factors and for both scaling factors suggests: “For large planning areas that cover more than one scaling factor….the most conservative (largest) value for α should be used in scaling the geomagnetic field. Alternatively, a planner could use a tool that is capable of performing analysis using a non-uniform or piecewise uniform geomagnetic field.” See Appendix
No
R 2.1 requires the study of peak and off-peak conditions. It is reasonable to study peak load conditions. However, the requirement to study off-peak conditions that may obviously be non-critical in some systems could be a waste of engineering resources that are in short supply due to the increase in study requirements in so many of the new standards and revisions. Also, there should be a % loading threshold so that effort is not wasted in a thermal study of a lightly loaded transformer that sees a relatively small GIC flow as low as 15 A.
No
GIC models will certainly require additional data beyond what is currently available. PacifiCorp suggests the extension of the Implementation period be 60 months. This would allow time for the software industry to develop viable models, the transformer industry to develop reasonable model data for older, installed transformers and for the industry to develop expertise in the science and tools that are still being developed for this standard. All of these activities must be addressed in order for the actual study efforts to begin successful implementation.
No
Please refer to PacifiCorp’s response to Q-7. If the new definition of the BES were incorporated into TPL-007-1, PacifiCorp could support the VRFs and VSLs as listed.
No
Please refer to PacifiCorp’s response to Q-7. The requirement for duplicative, iterative studies, using models and data that do not currently exist, for transformers that will not be part of the BES, unreasonably increases the costs to implement this standard without providing any protection to the BES. This valuable effort needs to apply to those elements that will protect the BES and reduce the risk imposed by a GMD event.
Yes
: PacifiCorp recommends modification of the current language to align with the new revised definition of the BES that became effective on July 1, 2014. The current language of TPL-007-1 includes many elements that have already been excluded from the BES based on the approved definition. The reintroduction of elements which have already been excluded would require unnecessary effort and increase costs for elements that do not affect the reliability of the BES. Removing non-BES elements, such as radial load, would reduce the number of transformers and the iterative process between the GIC assessment and thermal impact assessments and more accurately

reflect the actual risk to the grid of a GMD . The PacifiCorp system includes numerous 230-34.5 kV gnd wye-delta-gnd wye distribution substation transformers. In addition the system includes numerous non-BES 230-69 kV gnd wye-delta and gnd wye autotransformers that feed radial 69 kV systems and local networks. An outage of these transformers due to a GMD event would in no way affect the BES. PacifiCorp believes that NERC would be going significantly beyond FERC's authority in attempting to require analysis and mitigation for local distribution facilities
Group
Associated Electric Cooperative, Inc. - JRO00088
Phil Hart
Yes
No
AECI has concerns with the selection of a beta value for planning areas that span more than region. The issue was addressed at the technical conference, however statements were somewhat contradictory to what is described in Attachment 1. AECI requests additional clarification on the following language included in the standard: "Alternatively, a planner could use a tool that is capable of performing analysis using a non-uniform or piecewise uniform geomagnetic field". What tools are available to perform this? In the technical conference, "engineering judgment" was stated as acceptable but the language does not support this broad of a method and guidance does not describe a specific method for performing the calculation. Without direction on this alternative method, AECI would be forced to use a most conservative value which would not appropriately represent our area. Table 1 – Footnote 4: AECI believes that it would be acceptable to use load shed or curtailment of service as a primary method of achieving required performance, if the MW value of load or service does not exceed a maximum threshold. AECI requests the SDT consider revising language to allow for such a solution to be considered primary when reasonable.
Yes
No
AECI appreciates the SDT's acceptance of additional time for transformer thermal assessments, however it is still difficult to estimate the time required to complete these assessments when two major pieces are missing (the transformer modeling guide and thermal assessment tool). Although it has been stated these will be available soon, there may be unforeseen issues in utilizing the tool or the results produced, which may require a significant amount of time to address. AECI requests language in the implementation plan to include an allowance for extension if completion of these tools under development are significantly delayed. Additionally, AECI anticipates issues with meeting deadlines for DC modeling and analysis. Although 14 months for preparation of DC models internal to the AECI system seems reasonable, AECI's densely interconnected transmission system (approximately 200 ties internal and external to our system) may create timing issues when considering the coordination of models with neighboring entities. Our neighbors will be able to finalize their models on the 14 month deadline, leaving no time for coordination and verification of their data. AECI would request or the addition of a milestone for internal completion at 14 months, and an additional 6 months for coordination and verification with neighbors.
Yes
No
AECI has a couple issues with the currently available guidance and rationale on developing DC models. 1. AECI has concerns with the measurement or calculation of station grounding grid resistance. Various methods have been described in meetings and conferences where concerns were addressed with the current applicability guideline regarding calculation of a value with design modeling when modeling information is not available. Solutions have been offered outside of what is currently written, proposing a range of values that could be provided to entities without the means to measure or calculate. AECI requests clarity from the SDT specific to calculation of this value when modeling information is not available and if a range of value will be provided for use when all other options are not available. 2. AECI requests further consideration from the SDT in the applicability

guide regarding the modeling of neighboring systems. As written, the three options given do not consider highly interconnected transmission networks which require extensive consideration of neighboring (sometimes internal) systems. This issue couples with AECI comments regarding the implementation plan.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
No
Attachment 1 - A definition of and method for calculating “Effective GIC” should be explicitly provided. The use of different definitions and approaches due to a lack of standardization in adjacent regions could become problematic. A standardized approach would help to prevent different computational approaches, differing model results, and conflicting Corrective Action Plans (CAPs). Thus, it is important that the method for calculating “Effective GIC” be provided. The Transformer Mvar Scaling Factors used in PSSE are based on a paper published by X. Dong, Y. Liu, J. G. Kappenman, “Comparative Analysis of Exciting Current Harmonics and Reactive Power Consumption from GIC Saturated Transformers”, Proceedings IEEE, 2001, pp 318-322. Determination of geomagnetic latitude provided in Attachment 1 lacks clarity and precision. Figure 1 provided for this purpose may be used for very rough approximation only. The determination of geomagnetic latitude table in Attachment 1 is an approximate guide to determine the geomagnetic latitude of a given network. More accurate determination of geomagnetic latitude can easily be determined with a number of publicly available tools. Also, geomagnetic latitude changes over time, which may not be reflected by this static picture. Better results may be obtained by directing users to NOAA link: http://www.swpc.noaa.gov/Aurora/globeNW.html The geomagnetic field factor alpha in Table 2 in the Appendix should also be viewed as an approximation of alpha factors more readily calculated with the equation in Attachment 1. The geomagnetic field factor alpha accounts for regional differences and provides a floor from which applicable entities can expand if needed. This scaling factor can also be used to approximate non-uniform geoelectric fields in a geographically large service territory in steady-state calculations. The selection of 8 V/km is a reasonable compromise for a 100 year return event, as suggested by the FERC order. It is difficult to characterize a wide area system event by a single peak in a geographically confined local geoelectric/geomagnetic field enhancement. Although the value is primarily based on magnetic field measurements in Europe because such measurements are sparse in North America, it is consistent with the historical values measured in from North America. With additional measurements over time, a better value may be obtained. The 8 V/km is the best possible estimate at this time with the available data. The extreme value analysis provided in the GMD benchmark white paper provides mathematical rigor. From an engineering point of view it makes more sense to for spatially-averaged values to be used to assess wide-area impact, as opposed to 20 V/km estimate when only storm peaks were considered in the 2012 NERC GMD interim report.
No
Regarding Requirements R5 and R6 – The 15 Ampere (A) threshold is overly conservative if applied to all types of transformers. While 15A may be a reasonable number for some types of single-phase and shell-form transformers, the majority of core-type transformers may tolerate much higher GICs. It is recommended that different thresholds be established for various types of transformers. For technical justification, see Fig. 12 of the “Transformer Thermal Impact Assessment” white paper draft, based on which GIC below 50 Amps per phase has no impact on the transformer under study. Also see “ Methodology for Evaluating the Impact of GIC and GIC Capability of Power Transformer Designs” by Ramsis Girgis and Kiran Vedante presented at the IEEE Power and Energy Society General Meeting in 2013, which shows no significant impact under 150 A/phase. Other studies are available in support of the selective approach of thresholds. Recommend the adoption of a 50 Ampere across the board threshold. However, should the drafting team be unable to adopt this revised across the board threshold, then we recommend the two tier thresholds that follow: Transformer Types Threshold (Amperes) Single phase and shell-type 15A 3-phase core-type and other 50A A different threshold can be determined after entities have more experience. The white paper on the justification for the 15 A threshold is based on published measurements. This is a

prudent and conservative approach. Manufacturer-calculated values can vary widely depending on the manufacturer, and at this point in time, few have been validated by measurements. The degree of half-cycle saturation in single-phase units compared to core-type three-phase three-winding units is a matter that will require more study and clarity in the future. The susceptibility of these units to GIC depends strongly on the zero sequence magnetizing impedance of the transformer. The zero sequence magnetizing impedance has an important impact on the level of GIC at which a three-phase three-winding core type transformer will saturate. This parameter is not routinely measured in the factory, but it would be useful for entities to request this information from transformer manufacturers.
No
The time frame may not be realistic as it may take considerable time to get the database information from the owners' of those facilities. Also, the software tools may not be fully understood to determine which ones can provide accurate results to the requirement simulations. Even once the software and database information has been procured, the simulation time and development of the Corrective Action Plans would probably take longer than prescribed in the standard.
No
The VRF's and VSL's should be adjusted to reflect the revised threshold(s) proposed in the response to Question 3 – Transformer Thermal Impact Assessment.
Yes
Hardware based mitigation technologies need to be further proven in test situations before mass deployment.
Yes
Underground Transmission Feeders – The application of the current draft of the standard is problematic for Transmission Owners with underground transmission feeders. It fails to differentiate between overhead transmission lines and underground transmission feeders. While overhead transmission lines may be subject to the direct above ground influences of Geomagnetic Disturbances (GMD's), underground feeders are not. We recommend that an additional scale factor be created within the equation shown in Attachment 1, such that for all underground transmission feeders, there can be an adjustment factor within the power flow model, to reduce the impact of the induced electric field from one (full effect) to zero (full shielding) as necessary. Model Inputs - Due to the nature of GIC's and the calculation method employed, accurate and timely data on adjacent system equipment is essential to creating and maintaining the System models required by R2. Access to accurate input data on adjacent Responsible Entity(ies) equipment is key to the proper operation of GMD System models. This data is not normally readily available. So, there should be a requirement that all requested adjacent system equipment data be provided by the adjacent Responsible Entity(ies) within 90 days of a written request from another Responsible Entity. Model Results in Adjacent Systems - Adjacent Responsible Entity (ies) should be required to share their model assumptions and adjacent system results with other adjacent Responsible Entity(ies) within 90 days upon receipt of a written request. As currently written, the standard only contemplates the sharing of CAPs, but not any sharing of assumptions and results. Forecast Disagreements – Model results have important implications for Corrective Action Plans (CAPs). Adjacent Responsible Entity(ies) should be precluded from shifting GMD related costs to adjacent systems through inaccurate or inappropriate modelling inputs or computations, and/or cost shifting Corrective Action Plans (CAPs). So, should the respective results forecast--for an adjacent system and the interface elements between adjacent Responsible Entity systems -- be in substantial disagreement, e.g., say by more than 25%, or the forecast project substantial cross boundary impacts, then there should be a process for resolving such forecast differences, e.g., say to within +/-10%, and for mitigating such cross boundary impacts. The Planning Coordinator or Adjacent Planning Coordinators should be engaged to resolve substantially different forecast results to within reasonably acceptable levels. Cost shifting should be addressed and minimized initially through appropriate mitigation on the Responsible Entity's existing system through its CAP. Potential Cost Shifting and Cost Sharing – The potential for cost shifting between adjacent systems is a major concern for industry. Requirement 7.3 only contemplates an exchange of Corrective Action Plans (CAPs). However, how does the drafting team envision ensuring that actions taken in one area (or on one system) do not negatively impact adjacent Responsible Entities, e.g., PJM or ISO-NE CAP's negatively affecting NYISO entities? For example, a PJM CAP might result in GIC's flowing on adjacent NYISO interface and system

elements exacerbating a problem in NY. What recourse would a Responsible Entity(ies) have to prevent or minimize such adjacent Responsible Entity actions from negatively impacting their system, and shifting GMD related impacts and costs to their System? After mitigation, residual cost shifting should be addressed through cost sharing payment appropriate to the cost shifting caused by an adjacent Responsible Entity system and CAP. The Rationale Box for R5 references Part 5.3 which is no longer in the draft standard. Please correct Rationale Box wording to reflect the revised Requirement wording and Part numbering. The link to the report referenced in footnote 2 on page 11 is no longer valid. Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx The R1, R2 and R4 VSL's only include a Severe rating. There is no gradation of penalties. The process to decide which shunt compensation elements should be removed is not clear in the GMDTF application guides. The SDT should consider writing a white paper addressing this methodology. Is there a need to include a time requirement in Requirement R5 in order to account for the 12 calendar months provided for the responsible entity to perform the thermal impact assessment for transformers in accordance with Part 6.4, and still be compliant with the requirement in Requirement R3 of completing a GMD Vulnerability Assessment once every 60 calendar months? Propose to augment Requirement R5 with a requirement for the responsible entity to provide the required geomagnetically induced current (GIC) flow information to be used for the thermal impact assessment specified in the Requirement at least 12 calendar months before completion of the ongoing GMD Vulnerability Assessment cycle, which is due (at least) once every 60 calendar months. The process to decide which shunt compensation elements should be removed is not clear in the GMDTF application guides. The SDT should consider writing a white paper addressing this methodology.
Individual
Terry Volkmann
Volkmann Consulting, Inc
Yes
No
SDT has not adequately justified the size of the peak E-field area, nor has provided gudiance as to how analyze the area if so chosen by the PC or TP.
Yes
Yes
Yes
No
NERC should perform a cost and benefit study upon completion of the first 4 years of the standard. Once the initial vulnerability assessment is completed, knowledge of the risk and mitigation cost should exist.
Yes
There has not been any evidence provided by the SDT demonstrating the proper venting and discussion of the Space Weather aspects of this standard. This evidence must be provided prior to Final vote of this standard. The Electric Utility industry has no expertise to judge the Benchmark GMD event. Resting solely on the hand pick Space Science expertise on the SDT is not adequate. If this is adequate why even put the whole standard up for vote, just leave it to the SDT. Proper and inclusive expertise should be sought to review and comment on this technical aspects. This will help in getting FERC's approval.
Individual
shirin.friedlander@ladwp.com
ladwp
Yes

Yes
Yes
Yes
Yes
Yes
No
Individual
Neel Savani
George mason University/ naval Research lab
Group
Foundation for Resilient Societies
Thomas Popik
No
We do not agree with the draft standard organization because we believe that the standard does not follow requirements of FERC Order 779, per our other comments.
No
Comments on Attachment 1, “Calculating Geoelectric Fields for the Benchmark GMD Event” 1. The draft standard does not state the criteria for a “technically justified earth model” to be used as a substitute for the USGS model. 2. The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveshape to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment. The Standard Development Team does not present any evidence that this waveshape would be a “worst case” waveshape, only an assertion that this is a “conservative” waveshape for thermal analysis. 3. The geoelectric scaling factors do not include an adjustment for transformers located at the edge of water bodies. Comments on Benchmark Geomagnetic Disturbance Event Description 1. We do not agree with the statement, “Thermal time constants for hot spot heating in power transformers are in the 5-20 minute range.” Without testing of multiple transformer designs, this is an assertion not supported by statistically valid evidence. 2. We do not agree with the statement, “Since geomagnetic disturbance impacts within areas of influence of approximately 100-200 km do not have a widespread impact on the interconnected transmission system (see Appendix I), statistical methods used to assess the frequency of occurrence of a severe GMD event need to consider broad geographical regions in order to avoid bias caused by spatially localized geomagnetic phenomena.” A severe but localized event could still cause a cascading outage if it is unexpected. 3. Despite the statement, “any benchmark event should consider the probability of occurrence of the event and the impact or consequences of the event,” the Benchmark GMD Event does not incorporate safety factors consistent with the consequences of the event. 4. The Benchmark GMD event modeling is based on magnetometer data but not validated with actual GIC measurements at a variety of latitudes and earth resistivities. NERC should not use an unvalidated model when millions of lives are at stake and when GIC data exists at EPRI SUNBURST and elsewhere to validate (or invalidate) the NERC model. 5. The “Hotspot” hypothesis for geoelectric field maximums is not adequately supported by observatory data for North America. If NERC wishes to promote this hypothesis, it should be required to show that magnetometer observatory data does not move in tandem across wide areas of North America. 6. It is not prudent to use a limited period of January 1, 1993 – December 31, 2013 to predict a maximum geoelectric field of 8 volts/km that may occur with a frequency occur over hundreds of years. 7. The maximum geoelectric fields produced by the NERC statistical model for a severe solar storm (1-in-100 years) are at or below the fields and/or GIC measured in North America for

moderate solar storms. Therefore, the NERC statistical model must be wrong. See comments of John Kappenman in this NERC comment period. 8. The section "Impact of Local Geomagnetic Disturbances on GIC" is speculative and unsupported by actual data and experience. It relies on an unproven "hotspot" hypothesis. 9. IN "Appendix II – Scaling the Benchmark GMD Event" there is no scaling for a transformer being adjacent to a body of water when research shows that this adjacency increases GIC.
No
Comments on "Transformer Thermal Impact Assessment White Paper" 1. The premise of this white paper is that thermal heating is the only failure modality for transformers subjected to GIC. There have been many reports of vibration effects on transformers and vibration could be causing failures even without heating. The effects of shock or vibration do not require long time constants; near immediate damage might occur after a "GIC shock." It is an unwarranted assumption that NERC modeling needs to only account for thermal effects. 2. The thermal heating models presented in the white paper are not compared against experimental data. Therefore, the thermal models might be wrong. We cannot have the lives of millions of people dependent on unvalidated thermal models. Comments on "Screening Criterion for Transformer Thermal Impact Assessment" Quoting from the document: Half-cycle saturation results in a number of known effects: • Hot spot heating of transformer windings due to stray flux; • Hot spot heating of non-current carrying transformer metallic members due to stray flux; • Harmonics; • Increase in reactive power absorption; and • Increase in vibration and noise level. This paper focuses on hot spot heating of transformer windings and non current-carrying metallic parts. Effects such as the generation of harmonics, increase in reactive power absorption, vibration and noise are not within the scope of this document. 1. We could not find anywhere in the draft standard where the effects of vibration on transformers are addressed. 2. No validation of the thermal models or manufacturer capability curves is presented in the whitepaper, except for Figure 4 that appears to show results for a single test. The FDA would not accept safety tests of a drug in a single patient, nor should NERC and its Standard Drafting Team rely on a single transformer test when millions of lives are at stake. 3. If NERC, electric utilities, and transformer manufacturers are confident in the hypothesis that damage to transformers will require minutes of GIC exposure, we suggest that they subject representative EHV transformers to 60 seconds of 1,000-2,000 amp DC injection and record the thermal and vibration results.
No
We do not agree with the approach for the transformer thermal assessments. The timeline could be shortened by simply installing hardware blocking devices.
No
Because the requirements of the standard are inadequate, we do not agree with the VRFs and VSLs.
No
When the costs of a blackout from a severe solar storm could be in the trillions of dollars and the costs of mitigation are thousands of dollars per location--or less than a billion dollars in total for all EHV transformer locations--a cost-benefit analysis should be required.
Yes
Comments on TPL-007-1 1. Section 4.1 Functional Entities. Because "Load Loss," "Generation Loss", and "Interruption of Firm Transmission Service" will be allowed under the standard, operational entities should also include Transmission Operators, Generation Operators, Balancing Authorities, and Load Serving Entities. 2. In regard to FERC Order No. 779, 143 FERC P 61,147 et seq. issued May 16, 2013, this order states, "In the second stage, NERC must submit... one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and ongoing assessments of the potential impact of the benchmark GMD events…." Owners and Operators of the Bulk-Power System include generator owners and generator operators. Moreover, at page 41 of 77 pages, FERC Order No. 779, FERC states: "As noted in NERC's Comments, owners and operators of the Bulk-Power System, as opposed to NERC, will perform the assessments and special attention will be given to evaluating critical transformers (e.g. step-up transformers at large generating facilities);" Para 82 at Page 41 of 77. So, it is mandatory to include both generator owners and operators as having mandatory assessment duties, including those with split or shared ownership and operation. We ask that the Standard Drafting Team reconcile the authority of Reliability Coordinators and Transmission Operators for Operating Procedures under Stage 1 with the authority of other entities, including Generators Owners, in Stage 2 for "Generation Loss" and

“Interruption of Firm Transmission Service.” 3. Section 4.2 Facilities. For consistency with the FERC-approved definition of the Bulk Electric System, the low voltage limit should be 100 kV, not 200 kV. 4. The draft standard has no requirement for monitors to measure GIC flows during solar storms nor any requirement to maintain and archive data of GIC flows during storms. 5. GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow but there is no requirement to compare modeled GIC flows to measured GIC flows during solar storms. While measured GIC flows may not be immediately available, they can be measured in the future and used to validate GMD Vulnerability Assessments. 6. While GMD Vulnerability Assessments are to be provided to Reliability Coordinators, Transmission Planners, and other functional entities, there is no requirement for audit, review, or external approval of GMD Vulnerability Assessment methodology—just audit that that assessments have been performed. 7. The draft standard is not compliant with FERC Order 779 because it does not state that Corrective Action Plans cannot be limited to Operating Procedures or training alone. 8. There is no certification process for modeling software to be used in preparation of GMD Vulnerability Assessments. 9. Section 1.2 Evidence Retention. The draft standard states that “The responsible entities shall retain documentation as evidence for five years” but the solar cycle is 11 years. A more appropriate requirement would be to keep evidence in perpetuity.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
Yes
The SDT needs to correct the standard language as identified at the technical conference on 7/17/14.
Individual
Ayesha Sabouba
Hydro One
Yes
Yes
The benchmark event is reasonable and consistent with engineering practices. It accounts for regional differences and provides a floor from which applicable entities can expand if needed.
Yes
It is difficult to come up with a different threshold until entities have more experience.
Yes
The implementation period provides reasonable timelines.
Yes
Yes
Mitigation technologies need to be further proven in test situations before mass deployment.
Yes
The process to decide which shunt compensation elements should be removed is not clear in the GMDTF application guides. The SDT should consider writing a white paper addressing this methodology.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC

Yes
Yes
Yes
Yes
Yes
Yes
No
Individual
Paul Rocha
CenterPoint Energy
Yes
Yes
CenterPoint Energy commends the SDT's work on this issue. CenterPoint Energy believes the SDT work product is a significant improvement over earlier efforts resulting from the collaboration of NASA, the country's expert space agency, and electrical modeling experts from industry. Applied holistically, the design basis event would involve the convergence of a 100 year GMD event under conservative time domain characteristics coincident with worst case field orientation coincident with stressed system conditions, all of which would simultaneously occur with a frequency on the order of once every several millennia. Even so, CenterPoint Energy believes the conservative approach resulting from the collaboration of the experts on the SDT is appropriate and reasonable.
Yes
CenterPoint Energy appreciates the diligent efforts of the SDT and CenterPoint Energy is voting to approve TPL-007-1 as a reasonable set of requirements for GMD planning based upon the current state of the art in this evolving area of study. The 15 ampere threshold is less than the threshold level recommended by CenterPoint Energy in earlier comments, but CenterPoint Energy is willing to support that extremely conservative threshold if it is agreeable to the majority of industry stakeholders. Besides CenterPoint Energy, multiple other industry stakeholders expressed concerns about the transformer thermal impact requirements of the initial draft standard during the informal comment period. If the June, 2014 version of the draft standard is not approved by industry stakeholders, and if multiple parties continue to express concerns about the transformer thermal impact requirements of the standard, CenterPoint Energy offers the following thoughts and suggestions for modifying the standard for the second ballot. Read holistically, Requirements R6.1 and R5.2 require that G(t) be calculated based on benchmark GMD event waveform and, furthermore, that owners use that calculated waveform to perform a transformer thermal assessment. CenterPoint Energy understands and agrees that the prescribed approach is technically justified and can be implemented with training, proper tools, and reasonably accurate transformer data. However, there are no commercially available tools at this time. Even if one entity provides its tool for industry use, the situation is less than ideal because users cannot choose among two or more tools from multiple vendors and the tool will not have been vetted and improved based on feedback from multiple users, as is commonly done through beta testing of modeling software. Even if adequate tools are available, accurate data for most transformers is not available. Accordingly, CenterPoint Energy has come to believe that whereas the prescribed approach is technically valid and may be feasible to implement, it is at best an approximation limited by data quality and other uncertainties. CenterPoint Energy believes there are valid alternative ways to approximate the thermal impact of the benchmark GMD without calculating G(t). The benchmark waveforms selected

by the SDT using a 1989 historical event are reasonable and conservative based on the information available to the SDT, but almost certainly those waveforms will not occur in a future GMD event. The Transformer Thermal Assessment Whitepaper discusses using average GIC values over a two minute or five minute time interval as a valid assessment approach. One limitation of this approach is that using a single two or five minute interval from a 30 hour G(t) waveform fails to account for transformer heating and cooling that occurs from previous GIC peaks. CenterPoint Energy believes that heating effects from previous GIC peaks can be reasonably assessed by applying the peak GIC value, instead of the average GIC value, over a two or five minute interval. To err on the conservative side, a five minute interval can be applied. Another layer of conservatism can be applied by assuming that a transformer is loaded to 100% of its normal (continuous) rating coincident with the two or five minute interval that the peak GIC value is applied. For network elements, such as autotransformers, it is highly unlikely that the transformer would be loaded to 100% of its continuous rating due to the redundancy requirements of planning and operating standards (i.e., the system must be planned and operated to be at least n-1 secure). The approach described in the preceding paragraph would not require G(t) to be calculated. The owner would apply the peak GIC from Requirement R5.1 for five minutes to a transformer loaded to 100% of its normal rating, and compare this to an estimated (in most cases, generic) transformer heating model. CenterPoint Energy believes that the standard could be modified to allow such an approach by eliminating Requirement R5.2, which would reduce the burden upon planning entities while still enabling transformer thermal assessments to be performed. CenterPoint Energy believes the burden upon owners can be reduced by modifying Requirement R6 such that a transformer thermal assessment must be performed for the greater of 15 Amperes per phase or some percentage, such as 10%, of a transformer’s normal rating. For example, a transformer with a normal rating of 500 Amperes per phase would only be assessed if the peak GIC is 50 Amperes per phase. CenterPoint Energy believes that if the peak GIC value is less than 10% of a transformer’s rating, that transformer is not materially at risk of overheating, and at even less risk of failure, due to various reasons. Among other things, the transformer, especially an autotransformer, is likely loaded at significantly less than 100% of its normal rating throughout the GMD event and particularly so at a specific, limited moment when the peak magnitude of a geoelectric field coincides with the worst case field orientation from a rare (100 year) GMD event. Even if this highly unlikely set of circumstances converged for a single transformer, it is even less likely that this improbable set of circumstances would converge for two or more transformers, and the possible loss of one transformer is already addressed by planning and operating requirements. Accordingly, if changes in the transformer thermal assessment requirements are necessary based on the results and comments from the initial ballot, CenterPoint Energy asks the SDT to consider changes that would allow alternative, less onerous approaches of assessing transformer thermal impacts such as the approach described in these comments.
Yes
As indicated in our previous comment, CenterPoint Energy appreciates the diligent efforts of the SDT and CenterPoint Energy is voting to approve TPL-007-1 as a reasonable set of requirements for GMD planning based upon the current state of the art in this evolving area of study. CenterPoint Energy also agrees that, if the overall four year timeline is maintained, the implementation plan proposed by the SDT is reasonable. That said, based upon CenterPoint Energy’s experience with similar processes, CenterPoint Energy believes that 60 days is an unrealistic expectation for thoughtful implementation of Requirement R1. A rushed implementation of that threshold requirement, particularly given the new and evolving state of the art for GMD analyses for most applicable entities, will likely result in ineffective and inefficient implementation of the subsequent requirements of the standard. Stated otherwise, CenterPoint Energy is concerned that rushed implementation of Requirement R1 precludes thoughtful consideration and discussion of how to implement the new standard, potentially dooming the implementation from the very start. CenterPoint Energy recognizes that consideration and discussion of Requirement R1 can begin prior to Commission approval, but unapproved versions of the standard are always subject to changes throughout the approval process. If other stakeholders express similar concerns, CenterPoint Energy recommends that the SDT consider increasing the implementation timeline for R1 and increasing the overall timeline to allow thoughtful consideration and discussion of Requirement R1 by the applicable entities.
Yes

Yes
No
Individual
Eric Bakie
Idaho Power
Yes
Yes
Yes
Yes
Yes
Yes
No
Individual
Amy Casuscelli
Xcel Energy
Yes
Yes
Yes
Yes
No comment.
Yes
Yes
It is not clear as to whether an entity can rely on a 3rd party vendor/consultant to carry out R2 & R3 in lieu of maintaining a model 'in house'. Please consider modifying R2 to allow the use of a 3rd party vendor/consultant.
Group
ACES Standards Collaborators
Brian Van Gheem
No
(1) We would like to thank the SDT for the inclusion of the GMD Vulnerability Assessment process diagram. However, we still have a concern regarding how the applicable entities are identified in this standard. Requirement R1 has both the PC and the TP concurrently responsible, yet the NERC Functional Model clearly identifies that the PC “coordinates and collects data for system modeling from Transmission Planner, Resource Planner, and other Planning Coordinators.” We further recommend that the PC, because of its wide-area view, be the entity responsible for performing the

GMD Vulnerability Assessment . Likewise, GICs are not bounded by specific transmission planning areas. Moreover, this addresses the possible confusion which will arise between registered entities and auditors, regarding who is responsible for the requirements of these standards. The SDT should remove each reference to “Responsible entities as determined in Requirement R1” and instead properly assign the appropriate entity based on the responsibilities identified within the NERC Functional Model. (2) We believe the SDT should reconsider the facility criteria in this standard. The SDT should align TPL-007 with the current BES definition that went into effect on July 1, 2014. As written, the standard would appear to be applicable to a 230/69 kV transformer with a wye-grounded high side. However, that transformer does not meet Inclusion I1 of the BES definition and, thus, would not be part of the BES.
Yes
Although we agree with the guidance provided in Attachment 1, we still feel the SDT should develop an exception process mechanism for entities that are geographically located in the lower latitudes or certain Physiographic Regions to follow. For such entities, conducting such a study, for locations that are less susceptible to GMD events or less likely to produce large geoelectric fields, is an unnecessary burden on their resources.
Yes
No
We believe the overall timeline of four years is too short and burdensome for entities. With limited resources, software, and industry knowledge in this area, it will take entities time to construct the proper data models and conduct these new studies correctly. For smaller entities with limited staff and financial resources, this effort will be a significant challenge. Moreover, affected entities are already engaged in other high-profile NERC-related efforts, such as preparing for the multi-year implementation of Protection System Maintenance, Physical Security, CIP version 5, and the new BES definition. Moreover, there are numerous other standards that will go into effect during this proposed implementation period. We recommend extending the periods identified by the SDT to eight years, to allow industry an opportunity to fully engage in this effort.
No
We disagree with several of the SDT’s assignment of VRFs with this standard, and believe the most significant level assigned should be Medium. We believe an entity with an incomplete GMD Vulnerability Assessment or poorly documented thermal impact assessment does not significantly impact the reliability of the Bulk Power System. We also believe the SDT should identify measureable criteria for many of the VSLs and not rely just on identifying them as Severe.
No
We appreciate the efforts of the SDT to identify what it considers is the most cost effective means to accomplish the directives listed in FERC’s order. However, we question if doing nothing to mitigate the risk of GMD events is an acceptable solution as well. Using the materials generated on this topic so far, some entities, based on their geographic location or Physiographic Region, may not need to incur costs and conduct such GMD-related assessments. For entities that are geographically affected, these entities are likely to follow good utility practice and their own risk management policies when balancing mitigation costs with their own business strategies.
Yes
(1) We would like to thank the SDT on its continual efforts to include comments from industry to develop this standard. We appreciate the SDT including Attachment 1, Calculating Geoelectric Fields for the Benchmark GMD Event, and other technical knowledge listed under Guidelines and Technical Basis. (2) However, we believe Requirements R3 and R7 meet Paragraph 81 criteria and should be removed. Requirement R3 requires an entity to reassess its GMD Vulnerability Assessment every sixty months. We believe this standard does not pose a significant impact to the reliability of the Bulk Power System, and Requirement R3 could be classified as a “Periodic Update” under Paragraph 81 criteria. Likewise, an entity would use good utility practice and provide appropriate entities a copy of its Corrective Action Plan in a timely fashion. However, Requirement R7 requires the entity to provide a copy within ninety days. This would be classified as “Reporting” under Paragraph 81. Please revise or remove these requirements from the standard. (3) In Table 1 – Steady State Performance Footnotes, footnote 4 states that non-consequential load loss or curtailment of Firm Transmission Service may be needed to meet BES performance. This may raise similar questions to

the TPL footnote ‘b’ issue. Will there be a limit on the non-consequential load loss similar to the resolution done for the TPL footnote ‘b’ issue? (4) Thank you for the opportunity to comment.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst supplies the following comments for consideration: 1. Applicability Section a. ReliabilityFirst seeks clarification on whether “autotransformers” are considered as a subset of “power transformers” with section 4.2.1? If yes, ReliabilityFirst believes this should be further clarified. If no, ReliabilityFirst recommends including autotransformers in this section. b. ReliabilityFirst seeks clarification on whether the term “wye-grounded” includes “solidly wye-grounded”, “low impedance wye-grounded”, and “high impedance wye-grounded” windings? c. ReliabilityFirst requests the rationale why the applicability section does not include PC, TP, TO or GO with one or more "long" 200 kV and above transmission lines? Limiting applicability to transformer owners may limit available mitigation. 2. Generic comment related to instances of the word “days” - Throughout the draft standard there are a number of instances that refer to the term “days”. ReliabilityFirst recommends further clarifying the term "days" by preceding it with the term “calendar” or “business” days. 3. Generic comment related to instances of the term “geomagnetically-induced current (GIC)” - Throughout the standard there are many references to the term “geomagnetically-induced current (GIC)”. ReliabilityFirst recommends spelling this term out the first instance it is used and then using the acronym for every other instance. 4. Requirement R3, Part 3.1.1. - ReliabilityFirst believes the sub-part should use the NERC Defined term “On-Peak” instead of the undefined term “peak”. This would be consistent with Part 2.1.2 using the term “Off Peak”. 5. Requirement R7 - a. Requirement R7 requires the responsible entity to develop a Corrective Action Plan (CAP) but there is no companion requirement for the Responsible entity to “implement” the CAP. Without a requirement for the applicable Entity to “implement” the CAP, theoretically, the CAP could go on in perpetuity without completion and the responsible entity would still be compliant, and their System would continue to not meet the performance requirements of Table 1. ReliabilityFirst recommends the following for consideration: “Responsible entities as determined in Requirement R1 that conclude through the GMD Vulnerability Assessment conducted in Requirement R3 that their System does not meet the performance requirements of Table 1 shall develop [and implement] a Corrective Action Plan addressing how…” b. ReliabilityFirst recommends removing the language “Examples of such actions include: “since examples should be placed in the guidance section of the standard. ReliabilityFirst recommends modifying Part 7.1 as follows: “List System deficiencies and the associated actions needed to achieve required System performance such as, but not limited to:” c. ReliabilityFirst recommends including the use of automated UVLS in the list under Part 7.1. 6. Table 1 Footnote 4 - The Table 1, Footnote 4, which states "the likelihood and magnitude of Load loss… is minimized during a GMD event”, seems to discourage the use of UVLS. ReliabilityFirst seeks clarification on whether it is the SDT’s intent to discourage the use of UVLS. If so, can the SDT provide a justification for the exclusion of UVLS? Furthermore, Table 1, Footnote 4, consists of a number of "may" and "should" statements. Since Table 1 is performance requirements, should these statements in Footnote 4 be “shall” statements?
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
The revised organization is an improvement – no concerns.
No

1. Canadian entities do not benefit from the proposed scaling factor proposed for southern latitudes. The 8 V/km includes an arbitrary reliability margin on top of an event that already has a probability of occurrence of 1/100 years. The current NERC standards have four categories of events with varying levels of probability. A category C is the lowest probability event that requires a corrective action plan when performance requirements are not met. Category C events are generally recognized as having a 1/10 year probability (eg. breaker failures). A suggested improvement is to allow entities that have their own local magnetometer data to use the worst case(s) found since the 1989 event in Quebec as their benchmark GMD event. Those entities should then also describe where they include reliability margin in their analysis. One example might be to assume that the reactive power loss from all of their transformers are from single phase transformers rather than three-legged core, for example. 2. FERC Order 779 does not specify what the severity of the Benchmark GMD event should be. Paragraph 71 of Order 779 states the benchmark should be technically sound. Similar standards such as IEC 60826 have a minimum reliability design requirement of 1-in-50 and suggest higher reliability levels can be used if justified by local conditions. What is the basis and justification for selecting a 1-in-100 year event over say a 1-in-50 year event or a 1-in-200 year event? 3. Two references provided to support the benchmark GMD event, "Generation of 100-year geomagnetically induced current scenarios", Space Weather Vol.10, 2012, Pulkkinen, et al and "Credible occurrence probabilities for extreme geophysical events: Earthquakes, volcanic eruptions, magnetic storms", Geophysical Research Letters Vol 39, 2012, Love, provide strong evidence that the March 1989 GMD event has an occurrence rate of approximately 1-in-50 years (well in agreement other extreme events such as wind and icing etc.). Why develop a hypothetical benchmark event when a reasonable and known event already exists? 4. Page 5 of the NERC "Benchmark Geomagnetic Disturbance Event Description" states: "The frequency of occurrence of this benchmark GMD event is estimated to be approximately 1 in 100 years… The selected frequency of occurrence is consistent with utility practices where a design basis frequency of 1 in 50 years is currently used…" It is extreme to consider that the frequency of occurrence for a 1 in 100 year event is consistent or equivalent with the frequency of occurrence for a 1 in 50 year event. What is the technical basis/justification for this statement? 5. Figure 2 and Figure 3 of the NERC "Benchmark Geomagnetic Disturbance Event Description" illustrate the time series of the geoelectric field wave shape for the benchmark GMD event. From these plots it is clear that there is only one spike peaking at the 8V/km field intensity over the 24 hr period displayed. Pages 8 and 9 of the NERC "Benchmark Geomagnetic Disturbance Event Description" provide arguments that the benchmark is designed to stress wide-area effects caused by a severe GMD event. Please provide evidence that these characteristic peaks or spikes in geoelectric field measurements are a global phenomenon rather than a local phenomenon. 6. Page 13 last paragraph of the NERC "Benchmark Geomagnetic Disturbance Event Description" incorrectly states that a 25% engineering margin is added to the extreme value return level of 5.77 V/km. Note that 8/5.77 = 1.386 so in truth a 39% engineering margin was added to the 100-year return level. 7. The NERC "Benchmark Geomagnetic Disturbance Event Description" seems overly pessimistic base on the number of "fudge factors" or "engineering margins" added due to assumptions in its development. Please quantify the level of engineering margin added for each of the five assumptions made in developing the benchmark event. The five assumptions are identified below: a. Figure 2 and Figure 3 of the NERC "Benchmark Geomagnetic Disturbance Event Description" shows a typical GMD is an event where the geoelectrical field is changing both magnitude and direction relatively slowly over time. Such phenomena are classified as "quasi DC" or "slow transient" yet we simulate this event as more pessimistic steady state phenomena. In addition the reference, "Saturation Time of Transformers Under dc Excitation", Electric Power Systems Research , 56, 2000, Bolduk et al, provided to support the benchmark GMD event suggests that there is some time delay before the transformer responds to the GIC (seconds to minutes depending on the transformer). Using steady state analysis to simulate slow transients basically implies that we are assuming that the maximum geoelectric field intensity is applied permanent. What is the engineering margin added by this steady state assumption? b. The benchmark event described in the NERC "Benchmark Geomagnetic Disturbance Event Description" is assumed to represent a uniform geoelectric field in both magnitude and direction over a large area when in reality the geoelectric field is not uniform over a larger area. (In fact by using geoelectric field plots for large area such as that in Figure I-1 one can easily argue that the assumption of a large scale uniform electric field in both magnitude and direction is invalid, that over the wide scale the geoelectric field is in fact non-uniform in both magnitude and direction. The assumption of a uniform electric field in both magnitude and direction is only valid over the small

scale). What is the engineering margin added by the uniform geoelectric field assumption? c. For a given utility, the analysis (which as stated is to address wide area effects caused by GMD) requires a uniform geoelectric field in the north-south direction. A utility with a large north-south extent will select the worst case north-south geoelectric field defined by the northern most point of their system. This will result in ignoring the north-south geoelectric field reduction scale factor. What is the engineering margin added by this unscaled north-south geoelectric field assumption? d. While not directly stated Figure I-2 in the NERC “Benchmark Geomagnetic Disturbance Event Description” is derived by spatially averaging the data used to generate Figure 2b in reference “Statistics of extreme geomagnetically induced current events”, Space Weather Vol 6 2008, Pulkkinen et al. On page 3 of Pulkkinen et al tell us how to interpret Figure I-2. Simply put Figure I-2 tells us the number of 10 second measurement intervals that can in principle occur during one extreme storm with the specified geoelectric field magnitude (x-axis). Based upon Pulkkinen et al interpretation of their data, Figure 2, Figure 3 and Figure I-2 in the NERC “Benchmark Geomagnetic Disturbance Event Description” implies that in practice the worst case spike in the geoelectric field can be characterized for example by a 10 second duration transient peak at 5.77 V/km and a steady state 5 minute duration of 3 V/km main body. Choosing the short duration peak geoelectric field over some time averaged longer duration geoelectric field for the steady state analysis means that we are assuming that the peak geoelectric fields is applied permanently on the system rather than a more reasonable “time averaged” longer duration value. What is the engineering margin added by in assuming the steady state geoelectric field is represented by the transient peak value assumption? e. The extreme value analysis predicts that the maximum return value for the geoelectric field in the 1-in-100 year event is 5.77 V/km. A 39% engineering margin is added to scale that level up to 8 V/km. 8. Based upon the engineering margins identified in 7a through to 7d above please provide technical justification why the additional 39% engineering margin is required in 7e.
No
The transformer thermal assessment proposal is very new and has not been thoroughly examined by the industry or by transformer manufacturers. The GMD TF admits that manufacturers are just beginning to create hot spot heating models. Existing transformers may not have been assessed for GIC and manufacturers may not be able to calculate withstand on old designs. Perhaps the impact assessment should be limited to more critical transformers that have at least one winding greater than 300 kV. The GMD assessment could be used to assist the Transmission Owner in developing specifications for new or replacement banks. Rather than only a default level of 15 Amps, a larger exemption should also be allowed if the transformer was specified and confirmed by the manufacturer to withstand larger values. R6 should be limited to critical transformers (greater than 300 kV) that have a manufacturer GIC capability curve, where the assessment shows very high GIC levels (at or above the manufacturer confirmed withstand levels). Referring to the “Transformer Thermal Impact Assessment White Paper”: • Page 3, 1st bullet: Using the standard hotspot limit for the winding (120'C) will be too conservative and limit the capability of the transformer. Since GIC is so transient in nature and the really high values occur very seldom, more risk should be allowed. Please consider 130 or even 140'C hotspot temperature as a limit. • Page 3, last bullet: The equation for effective GIC is fundamentally wrong for the following reasons: o GIC does not divide within a transformer by the ratio of voltages nor is it determined by Amp-Turns. It is either essentially steady-state dc and divides by dc resistance, or it is a transient that charges the core and does not have amp-turn balance amongst the windings. o The GIC division between windings in an auto-transformer is primarily determined by the relative dc resistances of the grounding circuit (common plus ground circuit) and the LV line resistance including the system. o The formula given assumes ac or transients that are induced into the other circuit, which is not what we are trying to model. o Why would one want to know a single equivalent current? It doesn't make sense unless you also define an equivalent single dc resistance. And it would require more than one equivalent current, because this would change depending upon which way the current is flowing (HV to LV or LV to HV). o The white paper states that we have to use the generic formula. What about instances where the exact current relationship is identified through tests? o If the Standard is going to require us to calculate the temperatures within the transformer, then we should at least determine the correct current passing through the circuits of the transformer. • Page 4, point 1: It will cost utilities significant dollars (and lots of time) to obtain these capability curves for existing transformers. o Contrary to what is stated, every manufacturer will produce the GIC capability curve based on steady-state dc current because no GIC standard exists. No wave shape or timing will be assumed. Why would the manufacturer risk making assumptions related to wave shape or timing? o There is

no difference to the hotspot temperature for durations of 10 and 30 minutes. So why would a manufacturer differentiate between these? o The example curve (Figure 2) is quite useless. What is the rated ac current of this transformer that withstands thousands of dc amps? If this curve is for a 10 to 15 kA transformer that is a poor example to give. • Page 5, Figure 3: Heating to these temperatures (~200'C) contradicts Page 3, first point. Heating to these temperatures will result in free gas bubble formation, which puts the transformer at extreme risk of dielectric failure. • Page 5, point 2: o The statement, "Transformer hotspot heating is not instantaneous," is not really true for the clamping structure. Certain parts can heat up in as little as 10 to 15 seconds depending upon amount of flux; 20 to 60 seconds is typical. It happens very fast. (Manitoba Hydro has test data indicating this for step-up transformer tie-plates). o The statement, "The thermal time constants of transformer windings and metallic parts are typically on the order of minutes to tens of minutes...," is also not true. Winding time constants are typically 2 to 6 minutes. The metallic parts are much shorter. FROM CG Power Systems Canada Inc (Transformer Manufacturer) The NERC proposal to use a transfer function approach to estimate the heating effects of GIC on ANY transformer is fundamentally wrong. The transfer function can only be used to analyze the response of linear systems, or systems which can be lineralized in certain ranges of interest. The non-linear phenomena not considered include: 1. Conversion of unidirectional time-varying GIC into a corresponding steady state DC current, 2. Transformation of the GIC excitation currents to the corresponding half-cycle pulses, 3. Transformation of the half-cycle pulse into a Fourier series of harmonic currents, 4. Transforming the fundamental frequency (load) current and GIC derived harmonic currents into heating of the non-linear materials of the core and clamping system. Due to these inaccuracies the thermal response tool (transfer function) can only be used under the following conditions: 1. The thermal response tool is adjusted to the specific transformer being analyzed (by comparing design to test results or by directly testing the transformer and adjusting the parameters of the transfer function), 2. The thermal response tool is only used in the range of the tested dc currents (the extrapolation of the response beyond the tested dc currents will likely result in highly exaggerated results), 3. The thermal response tool is not used on unknown designs (as it will most certainly result in the wrong values for the temperature rise of metallic parts). It may be a good idea if some treatment is included in the transformer white paper on how to include GIC withstand capability in the specifications of transformers when the power utilities go out for tender. In some instances, there is no specific requirement and a customer just wants to know what is the transformer withstand for GIC, that is not an issue. Others will include a specific curve and say the transformer must withstand it. However often times this curve is not indicative of what the transformer will actually see. Frequently seen is the exact copy of a profile put forth in Ramsis Girgis' paper "Effects of GIC on Power Transformers and Power Systems" which is itself roughly 5 times greater than the 1989 GIC event. Every transformer has a defect. Some of those defects will affect GIC capability. Yet there is no discussion in this paper about common defects that would limit capability. Manitoba Hydro has no objection to doing assessments according to the white paper but be consistent in the accuracy desired at each step. Don't make step 1 totally inaccurate and then try to make step 2 highly accurate. Can NERC tell us how many transformers failed (or are suspected to have failed) due to GIC over the last 10 years?
Yes
The implementation plan is ok if the scope of transformer thermal assessment is limited to critical transformers with GIC capability curves as described in question 3 above.
Yes
No
Costs and benefits of mitigation have not been explored in any of the GMD reference materials that Manitoba Hydro could see. TPL-007-1 is not consistent with TPL-001-4 in that mitigation is required on a 1/100 year event. TPL-001-4 limits mitigation to credible n-2 disturbances, which typically have around a 1/10 year probability (eg. breaker failure). Some of the extreme disturbances recommended to be studied in TPL-001-4 may only have a 1/30 to 1/50 year probability. In addition to the 1/100 year GMD event, it is assumed that reactive power resources will also be unavailable unless a harmonic performance assessment has been completed to verify the resources remain connected. In section 4.3 of the GMD planning guide, the drafting team notes that there are limited tools available to perform appropriate harmonic analysis of a system wide GMD event. Making the conservative assumption that reactive resources are not available, makes the event very

conservative. Given the low probability, a 1/100 year GMD event with or without reactive power loss (capacitor banks and SVCs) should be considered an extreme event, and it should be up to the Responsible Entity to perform an evaluation of the possible actions to take to avoid Cascading, for example, however it shouldn't be mandatory for the Responsible Entity to implement those actions. This is a more consistent approach with TPL-001-4. If a Transmission Owner proposes a mitigation for their transformer (eg. neutral blocking device), it should be confirmed by the Planning Coordinator that the mitigation is acceptable and does not create any other adverse impacts on other equipment.
Yes
Note 4 in Table 1 does not allow curtailment of firm transfers as a primary method of achieving performance. This is a significant "raising of the bar" compared to TPL-001-4. Note 9 of Table 1 for that standard permits curtailment of firm transfers as a permissible correction action as long as there is an appropriate re-dispatch of resources. Note 4 of TPL-007-1 should mirror Note 9 of TPL-001-4. Compliance Monitoring Process 1.1. Compliance Enforcement Authority reads: "As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards." Only the Public Utilities Board (PUB) can enforce Manitoba Hydro's compliance with the NERC Reliability Standards, so this is not accurate for Manitoba Hydro's purposes. That provision should be revised to ensure it is applicable to Canadian entities. A trial period should be given to ensure that the standard as written can in fact be applied and enforced.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
The reordering of requirements following the consecutive steps is improving the standard. However, the GMD Vulnerability Assessment in requirement 3 needs clarification. First, it would be helpful to refer to Table 1 for this Assessment. Second, it is not clear what Assessment needs to be done. How could this event of increased dc current on the system analysed in steady state cause the transformer saturation and then the removal of compensating devices or Transmission Facilities ? How is one going to analyze the effects of harmonics on the tripping of protection systems ? The diagram in Attachment 1 is a good start, but it should be developed more to clarify all those elements.
No
The benchmark GMD Event is a new approach that needs to be well mastered before being adopted. Hydro-Québec TransÉnergie is concerned with the Benchmark GMD Event proposed in Attachment 1 and the high value of the geoelectric field of 8 V/km: • The value is not based on direct measurement of E, but it is deduced from B. The link between both measurements is not always linear and the relation is complex because they are not plane waves. E readings do exist and they should be considered directly in this evaluation of a GMD Benchmark. • The data comes from European values translated and adapted to the North American situation, but without considering local geomagnetic field, which are part of the polar and sub polar areas. • The B field should not be considered uniform, especially for a very wide area. • The maximum statistical data of E field during 167 months is under 3 V/km, which did happen only 7 times for a total time of less than two minutes. The 8 V/km is too pessimistic value and real historical American or Canadian values should be reconsidered. Since the approach is recent and is based on many assumptions mentioned, and because an eventual assessment may bring corrective actions with surprisingly high costs, it is proposed to adopt a prudent approach with regards to compliance. We propose that compliance could be completed with two levels as it is done in TPL-001-4, such as basic Planning Performance Requirements and Performance in Extreme Events. Applicable Entities would have to comply with the performance requirements of the first category, but they would only need to do the evaluation of possible actions to reduce the likelihood or mitigate the consequences for the second category. Such an approach could be applied in TPL-007-1. The application could be done on two different GMD benchmark: 3 V/km for the first category, and 8 V/km for the second category. We think this could be very helpful for the compliance of such a new approach.
No

The 15 A criterion should not be applicable for three-phase, three limb power transformers as it has been demonstrated by the industry that these transformers are far less sensitive to DC currents than single-phase and three-phase five limb power transformers as those tested and used to define the criterion. We recommend that another criterion (higher DC current) should be considered for three-phase three limb power transformers. We also recommend considering to relax the 15 A criterion for specific transformers for which it would be demonstrated with measurements and statistics that they are operated significantly below their nominal power. The effect of ambient temperature should also be considered as it significantly reduces the heating of power transformers.
No
This implementation plan is highly dependent on the availability on time of study tools. Please make sure that sufficient delay for tool development is considered and that stages are postponed in consequence.
No
Taking into account of the considerable potential expenses, without completed studies and assessment, the cost of mitigation measures can't be evaluated.
Yes
See question 3. As mentioned, it should be considered that the establishment of a GMD benchmark has been done with a new method of analysis and it needs to be validated before requiring compliance based on those estimated values. We encourage the Standard Drafting Team to consider a two level Performance Requirements as proposed in question 3.
Individual
Don Schmit
Nebraska Public Power District
Yes
No
We have major concerns on the Beta value in scaling the geoelectric field. Per the discussions at the July Technical Conference, it was brought up that between the IP1 and IP2 conductivity regions the difference between beta values is extremely large (0.94 versus 0.28). The task force formal response was to utilize the highest beta value for the study area which involved both of these regions. This results in the study being extremely conservative and increases the risk that unnecessary mitigations could be required. To address this issue, we request that the Standard Committee provide more detailed conductivity maps with additional conductivity regions to address where abrupt changes between conductivity regions as they exist now. In addition, we request that the Standard Committee provide additional guidelines on how the geoelectric field is calculated with a transmission line being split between two different conductivity regions. For example, is it acceptable to base the geoelectric calculation on a percent line length in each conductivity region? In addition,it is recommended the standard specifically include provisions that Engineering judgment is allowed to calculate realistic geoelectric values in a large study area.
Yes
No
The 60 calendar day time frame for the R1 requirement is too short. Our concern is the minimal time to determine which entities and subsequent responsibility assignments. The level of communication may have complexity and we would like to account for that in the process if possible. We would request the 60 days be increased to 6 months. Another concern is with Requirement R6 and the 36 calendar month time frame. Our concern is performing the thermal analysis for older equipment which does not have GIC data available or other design data available (for example if manufacturer is no longer available) . Obtaining and evaluating data for older transformers is a major concern. Also, there is a concern in reference to the GMD Assessments, specifically the harmonics and evaluating this data as well. We request extending the time frame to a 42 calendar month time frame.
Yes

No
Our concern in reference to Mitigation Costs associated with the applicability section ‘4.2.1 Facilities that include power transformer(s) with high side, wye-grounded winding with terminal voltage greater than 200 kV.’ Our concern is how the term ‘ Facilities’ is used in this section. Currently, we assume that transformers are the main focus. As we look to the future, our concern would be other ‘equipment/Facilities’ being included but not specifically defined. We would like to see more specifics on what type of ‘equipment/Facilities’ that would be defined and associated with this standard. We feel this would give us a better handle on managing our Mitigation Costs.
No
In all of the technical presentations, there has not been an example for the thermal analysis for an older transformer without any manufacturer GIC data/curves available. It is mentioned that IEEE has a standard to address this. The issue is GIC thermal curves/GIC data are not available for the majority of the existing power transformers. Even the transformer manufacturers at the technical conferences indicated it is unrealistic to expect GIC curves/data on existing older transformers. As we understand it, the extremely conservative IEEE method will have to be utilized which increases the risks of having to implement likely unnecessary mitigation plans. Even on new transformers being purchased today, when the transformer manufacturer was asked about GIC curves/data, the transformer manufacturer does not understand the requests and could not provide the GIC information. The TLP-007-1 committee needs to provide more information/examples on the thermal transformer assessment for transformers with no available GIC data. In addition, please provide or clarify what transformer data is required to perform this type of thermal assessment. The GMD assessment requirement for other facilities (capacitor banks, protective relays, etc.) is extremely vague. It is unrealistic to require a transmission owner to model their completed transmission system in software such as EMTP. However this is the only type of software today that can model the harmonics and transformer half cycle saturation to determine where other facilities could have potential problems. The TLP-007-1 standard needs to be more specific in what other facilities are to be modeled and reviewed for equipment damage or false protective relay operations or have these considerations removed. How to model these facilities also needs to be addressed, since it not feasible to model the complete transmission system. For example, what level harmonics are acceptable for protective relaying before a false trip occurs? This relay data information is typically not available.
Individual
Bill Temple
Northeast Utilities
Yes
Consider redrafting the note at the end of the flow chart from “Operating Procedures and Mitigations Measures (if needed)” to say “Operating Procedures and Mitigation Implementation Actions (if needed)”.
Yes
Yes
Yes
Yes
Yes
Yes
Request feedback on the differential focus in the standard between Thermal and Harmonics analysis. SDT Team should consider limiting Requirement 3 part 3.3 to only Reliability Coordinators and Planning Coordinators.
Individual

Frederick R Plett
Massachusetts Attorney General
No
Footnote 4 to Table TPL-007-1 states that load loss and or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. I disagree wholeheartedly. If there is an inexpensive way to mitigate, fine, but for a 1 in 100 year or less frequent event, curtailment or load loss perhaps ought to be the primary means of achieving required performance - otherwise this would become a requirement to spend money for little good purpose.
Individual
Martyn Turner
LCRA Transmission Services Corporation
Yes
Yes
Yes
Yes
Yes
Yes
No
Individual
Johannes Raith
Siemens AG Austria - Transformers Weiz
Here is my comment about transformer models to calculate the thermal transformer response during GIC: A thermal response tool is a very suitable method to evaluate the thermal risk of a transformer during a solar storm. But it is essential, that the simulations are based on calculation models what consider the specific transformer design. These models consider design elements like tie bars, clamping plates or tank shielding. Also the thermal influence parameters (cooling surface, thermo-hydraulic behavior) must be considered. Such calculation models can be also verified by special GIC tests. Of course, if a test in a laboratory is done, then the influence of the laboratory setup must be considered in the simulation. Such tests are described in the paper "GIC strength verification of power transformers in a high voltage laboratory" 1). 1) J. Raith, “GIC strength verification of power transformers in a high voltage laboratory”, (GIC workshop, Cape Town, 2014)

Individual
Kayleigh Wilkerson
Lincoln Electric System
No
How should the Beta value be used to scale the geoelectric field? The standard states 'For large planning areas that cover more than one scaling factor from Table 3, the most conservative (largest) value for β should be used in scaling the geoelectric field.' For example, using the largest value for β for the state of Nebraska results in using the value for IP1 instead of IP2 although 80% of the state resides within the IP2 region. Furthermore, a planning area that uses the largest value for β may result in adjacent planning areas in the same region using different values for β. To account for this issue, LES suggests modifying the standard to allow for the use of engineering judgment when determining the value for β.
No
Recommend the time to implement Requirement R1 be extended to 6 calendar months from its current schedule of 60 calendar days. This added time would allow the Planning Coordinator, in conjunction with each of its Transmission Planners, adequate time for the coordination necessary in determining the individual and joint responsibilities. In reference to Requirement R6 and the associated 36 calendar month implementation, recommend extending the time frame to 42 calendar months in consideration of the length of time for retrieval and evaluation of data when working with older equipment (i.e., transformers).
Group
FRCC Regional Entity Committee & Compliance Forum (FRCC RECCF)
Peter Heidrich
Yes
No
Scaling Factor for FRCC Region The FRCC RECCF believes that the Standard Drafting Team (SDT) should not move forward until a technical basis is developed for the scaling factor for the FRCC Region. At this time, the SDT has acknowledged that a scaling factor for the FRCC Region does not appear to have been developed as part of the supporting documentation for this Standard. In the alternative, the SDT has selected the value of 1.0 for a scaling factor, however, the SDT has not published any data as to how this value was determined. Without any technical justification supporting the currently proposed value of 1.0, the FRCC RECCF argues that this value was selected merely because it is a round/whole value, and that it is devoid of any technical analysis to the effect the other Regions were studied. If this value, or any other value, continues to be proposed without any technical justification, the FRCC RECCF may argue that this value is "arbitrary and capricious" under 5 U.S. Code § 706(2)(A). Therefore, the FRCC RECCF requests that the SDT delay any further proposals until a technically justified factor is developed. In the alternative, the FRCC RECCF requests that the FRCC Region be excluded from the rulemaking until a factor is technically justified. Cost Analysis The FRCC RECCF would like to see a cost analysis performed for this proposed standard. As described in a later comment, the FRCC RECCF would prefer a CEAP performed for this Standard. The FRCC RECCF reasons that this Standard will be costly and that the benefits are vague for the FRCC Region, and therefore requests that a cost-to-benefit analysis be performed for each specific NERC Region. The FRCC RECCF prefers the CEAP process to a separate process, such as a request to the Government Accountability Office to assist in a cost benefit analysis, and therefore requests that the SDT commence immediately on developing a CEAP. In support of this request the FRCC RECCF would like the SDT to consider the NARUC (National Association of Regulatory Utility Commissioners) resolution, "Resolution Requesting Ongoing Consideration of Costs and Benefits in the Standards development process for Electric Reliability Standards" approved by the NARUC Board

of Directors July 16, 2014 and included as an attachment herein. Peer Review The FRCC RECCF requests that NERC coordinate a peer review of the scientific information that is being utilized for the basis of this rulemaking in accordance with the Office of Management and Budget’s December 16, 2004 Bulletin that “establishes that important scientific information shall be peer reviewed by qualified specialist before it is disseminated by the federal government.” This Bulletin directs federal agencies to perform peer reviews of influential scientific information before it is fully disseminated, e.g., through a FERC NOPR. TPL-007-1 is an ideal example of a regulatory action based on scientific assessments that is covered by this Bulletin. Although NERC is not a federal agency, it is performing the review and development of rules in FERC’s place to an extent, and so NERC, in coordination with FERC, should be tasked with the peer review of any influential assessments that NERC is relying on as a basis for the proposed Standard. If NERC does not perform this review and the this Standard is eventually sent to FERC for approval, FERC’s rulemaking ability may be hindered to a great extent if a peer review process has to be initiated at that later stage rather than being performed at the NERC rule development stage. Therefore, the FRCC RECCF believes that NERC should immediately initiate a peer review of any influential scientific assessments in accordance with the Bulletin that the SDT is relying upon.
Yes
No
Based on the questionable validity of the conductivity references in the ‘white paper’ and the lack of technical justification supporting the assumptions made by the SDT in reference to peninsular Florida and other portions of the continental United States, the FRCC RECCF recommends that the implementation plan be modified to allow the FRCC region (and other appropriate areas) to delay portions of the implementation of the proposed Reliability Standard until such time as the USGS and/or Subject Matter Experts (SMEs)can determine the appropriate conductivity value for peninsular Florida (and other appropriate areas). In accordance with the above concern, the FRCC RECCF requests that the implementation of all of the Requirements be delayed for peninsular Florida (and other appropriate areas), pending the re-evaluation of the regional resistivity models by the USGS or SMEs. In the alternative, the FRCC RECCF requests that Requirements R3 through R7 at a minimum be delayed as discussed as the additionally requested re-evaluations are pertinent prerequisites for those Requirements. If the second option is chosen, the FRCC RECCF recommends insertion of the following language into the Implementation Plan after the paragraph describing the implementation of R2 and prior to the paragraph describing the implementation of R5: “Implementation of the remaining requirements (R3 – R7) will be delayed for the FRCC Region pending resolution of the inconsistencies associated with Regional Resistivity Models developed by the USGS. Once the conductivity analysis is completed and appropriate scaling factors can be determined for the peninsular Florida ‘benchmark event’, the FRCC Region will implement the remaining requirements from the date of ‘published revised scaling factors for peninsular Florida’ per the established timeline.” This delay will provide a level of certainty associated with the results of the GMD Vulnerability Assessments and Thermal Impact Studies conducted in the FRCC Region, thus establishing a valid foundation for the determination of the need for mitigation/corrective action plans.
No
The FRCC RECCF believes that the VRF levels for Requirements R3, R6 and R7 are inappropriately elevated for the potential risk exposure to the BES for a GMD Event and recommends the ‘high’ designation be lowered to ‘medium’ for all three (3) requirements. The probability of a severe GMD event occurring has been estimated and analyzed as a 1 in 100 year event and this probability should be taken into consideration when assigning the VRF levels. Additionally, for the majority of the applicable portions of the continent the risk to the BES of a GMD event being severe enough to result in instability, uncontrolled separation, or cascading failures is very low. Assignment of a ‘medium’ VRF is appropriate for R3, R6 and R7 because, if violated, these requirements could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system, but are unlikely to lead to bulk electric system instability, separation, or cascading failures.
No

The FRCC RECCF requests the Standard Drafting Team (SDT) to apply the Cost Effective Analysis Process (CEAP) to this project for each respective NERC Region. In the alternative to a full CEAP, the FRCC requests that a Cost Effectiveness Analysis (CEA) Report be produced for each respective NERC Region. The NERC Drafting Team Resources document, Version 1, Effective July 2, 2014, states that each NERC Requirement "should establish an objective that is the best approach for the bulk power system reliability, taking account of the costs and benefits of implementing the proposal" (see page 3 of document). NERC's Whitepaper on the "Implementation Plan of NERC Cost Effective Analysis Process, "CEAP"," states that "[t]he CEAP estimates the implementation costs of a draft Reliability Standard and the effectiveness of the proposed standard if approved and implemented in support of the respective reliability objective." (see page 1 of the document). The Whitepaper continues stating "[c]ost considerations are inherent in the development of Reliability Standards," and "[t]he CEAP affords stakeholders an opportunity to share projected cost information regarding implementation of the draft standards and provides the opportunity to offer alternatives that would be equally, or more efficient at achieving the reliability objective of the draft standard while also taking into consideration implementation costs." (see FRCC RECCF response to Q2 - initial threshold analysis) Finally, the Drafting Team Reference Manual, Version 2, Effective January 2014, states in the Introduction that the SAR and Standard Drafting Teams will assist in the analysis and/or development of the cost impact analysis and cost analysis respectively (see page 4 of the Manual). The impact of a geomagnetic induced current (GIC) on a TO's system is greatly dependent on the geomagnetic latitude and the earth conductivity below an applicable TO's transformer. In the supporting documentation that the SDT has provided during the balloting process, there has been zero evidence indicating that a transformer has ever been detrimentally affected that lies in the low latitude United States, e.g., Florida/FRCC Region. Additionally, the SDT has failed to produce earth conductivity information that is specific for the FRCC Region. Consequently, it became apparent that the SDT never analyzed the cost for implementation of this Standard as the SDT was unaware of the cost of purchasing the required modeling software and acknowledged the absence of performing any benefit-to-cost analysis. The above findings illustrate that the proper analyses for determining benefit to cost ratios have not been performed. Therefore, the FRCC RECCF requests that the SDT perform a CEAP and specifically that the CEAP take into consideration the geological differences that are material to this standard, i.e., latitude. The CEAP process allows for consideration and comparison of all implementation and maintenance costs. In addition, the process allows for alternative compliance measures to be analyzed, something that may benefit those Regions where the reliability impact may be low or non-existent, i.e., lower latitude entities. In support of this request the FRCC RECCF would like the SDT to consider the NARUC (National Association of Regulatory Utility Commissioners) resolution, "Resolution Requesting Ongoing Consideration of Costs and Benefits in the Standards development process for Electric Reliability Standards" approved by the NARUC Board of Directors July 16, 2014 and included as an attachment herein.
No
Individual
Brett Holland
Kansas City Power & Light
Individual
Thomas Foltz
American Electric Power
Yes
Yes
Yes
AEP has had discussions with at least one transformer manufacturer on obtaining the required GIC thermal response data for existing units in order to conduct thermal assessments. One manufacturer owns the data for a large majority of our current fleet, and indications are that it may not be possible for them to obtain the required information. If such is the case, AEP may be required to utilize generic models for a large percentage of its transformer fleet. As a consequence, the generic

thermal models will assume a significant role in the analyses and subsequent results. Due to the anticipated criticality of the generic models 1) the proposed standard cannot be properly reviewed, and its impact fully determined, until the models are provided, and 2) the models must be provided while the project is still active, so that industry has the opportunity to provide comments. Otherwise, industry risks being presented with generic models they don't agree with without a forum to debate them. During the technical conference, the drafting team inferred that "sound engineering judgment" would be allowed in assessing thermal vulnerability. AEP agrees with this approach; however the current draft provides no such allowance. The standard would have to clearly indicate what is and is-not "sound engineering judgment" so compliance can be clearly shown and proven. AEP requests that the drafting team incorporate this concept that they apparently believe is already is allowed by the proposed standard. The proposed standard specifies no obligation that any of the applicable Functional Entities carry out the "suggested actions" in R6. It would appear that the authors of the draft RSAW concur, as the RSAW likewise shows no indications of any such obligation. While R7 does require the development and execution of a Corrective Action Plan, its applicability is limited by R1 to the PC and TP, and it is unclear if any other mechanism exists by which the PC/TP can require the TO/GO to take action. If it is the expectation of the drafting team that the TO and/or GO implement the R6 "suggested actions", the standard must be revised to clearly indicate this intention.
No
Given the unavailability of the generic transformer thermal models and the lack of clarity surrounding the R6 "suggested actions", it is not possible to determine if the Implementation Plan's overall timeline of four-years is sufficient.
Yes
Yes
Yes
Paragraph 3 in the "Rationale for Requirement R5" box referenced part 5.3 which does not exist in Requirement 5. Paragraph 3 should read "The GIC flows provided by part 5.2 are used to convert the steady-state GIC flows to time-series GIC data used for transformer thermal impact assessment. Additional guidance is available in the Thermal Impact Assessment white paper:" For clarity, please add "to harmonics" to the end of footnote #3 in Table 1 so foot note #3 reads "Protection Systems may trip due to the effects of harmonics. GMD planning analysis shall consider removal of equipment that the planner determines may be susceptible to harmonics."
Individual
Rick Terrill
Luminant Generation Company LLC
Yes
We do not have enough information to effectively evaluate this methodology.
Yes
Yes
While it is unclear how these performance requirements effect a GO, many factors should be considered when developing a mitigation plan. Table 1 is not clear for how it applies to a GO. Costs should be balanced with risk in any mitigation plan. If implemented as written, the standard could allow for a TP to mandate that a GO purchase multiple spare transformers separate and apart from any consideration or costs are risks for the generating unit.
Yes
(1) In order to obtain the thermal response of the transformer to a GIC waveshape, a thermal response model is required. To create a thermal response model, the measured or manufacturer-

calculated transformer thermal step responses (winding and metallic part) for various GIC levels are required. A generic thermal response curve (or family of curves) must be provided in the standard or attached documentation. Without the curve, the transformer evaluation cannot be performed. The reference curves and other need data should be provided for review prior to ballots on this standard. (2) How will entities determine if their transformers will receive a 15Amperes GIC during the test event? (3) It seems like the requirements as written will not incorporate well into a deregulated market with non-integrated utilities. For instance, a TP or PC could instruct a GO to purchase new equipment or shut down their generating unit. This could potentially introduce legal issues in a competitive market. The standard should be revised to eliminate these unintended consequences.
Individual
Glenn Pressler
CPS Energy
Yes
Please clarify in Requirement R3 that steady-state analysis results should be documented solely in regard to the GMD study, to avoid confusion and duplicative reporting in regards to documentation required by TPL-001. In Table 1, the event listed under the “Event” column should be “the GMD event”. The current language states, “Reactive Power compensation devices and other Transmission Facilities removed are a result of the GMD event”, which indicates this is a system response to the GMD event, and should not be considered the event in and of itself. If the intention of this language is to generate further analysis due to this system response, there is no need to explicitely state it, as it is already implied by Table 1, Section a, which states Voltage collapse, Cascading and uncontrolled islanding shall not occur, which indicates further analysis is warranted.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
No
AZPS would like for the Drafting Team to consider extending the overall Implementation Plan to a 5-year period, rather than the proposed 4-year period as written. Rather than the proposed 12 month period that has been set aside for Requirement 1, we request for the drafting team to allow an overall 24 month period. Much of the industry has no experience with respect to modeling GIC currents and using the new tools being developed; therefore, further education and learning would be needed for those responsible for performing the required studies. This will require significant company resources and the additional 12 months would provide a more reasonable time to accomplish.
No
AZPS believes that a binary (i.e. compliant / non-compliant) should automatically fall under the severe category. Analysis of the impact to the system should still be done and the VSL should reflect that assessment.
Yes

Although AZPS is comfortable with the SDT approach, the SDT might want to consider doing some type of cost assessment of the various technology solutions available to date to inform industry discussions.
Yes
AZPS would like for the drafting team to align the inclusion threshold with those elements that are considered BES elements, based on the new revised definition of the BES that goes into effect July 1, 2014. In doing so, non-BES transformers should not be included. For example – if there is a transformer with a high-side connected at 200kV or higher with a low-side connected at 69kV, it should not be included unless included based on exception. The standard should also not be applicable to generators that are not included in the BES.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Individual
Ayesha Sabouba
Hydro One
Yes
Yes
The benchmark event is reasonable and consistent with engineering practices. It accounts for regional differences and provides a floor from which applicable entities can expand if needed. The determination of geomagnetic latitude table in Attachment 1 should probably be interpreted as an approximate guide to determine the geomagnetic latitude of a given network. More accurate determination of geomagnetic latitude can easily be determined with a number of publicly available tools. The geomagnetic field factor alpha in Table I in the Appendix should also be viewed as an approximation of alpha factors more readily calculated with equation xx in the Appendix. The geomagnetic field factor alpha accounts for regional differences and provides a floor from which applicable entities can expand if needed. This scaling factor can also be used to approximate non-unniform geoelectric fields in a geographically large service territory in steady-state calculations. The selection of 8 V/km is a reasonable compromise for a 100 year return event, as suggested by the FERC order. It is difficult to characterize a wide area system event by a single peak in a geographically confined local geoelectric/geomagnetic field enhancement. Although the value is primarily based on magnetic field measurements in Europe because such measurements are sparse in North America, it is consistent with the historical values measured in from North America. With additional measurements over time, a better value may be obtained. The 8 V/km is the best possible estimate at this time with the available data. The extreme value analysis provided in the GMD benchmark white paper provides mathematical rigor. From an engineering point of view it makes more sense to for spatially-averaged values to be used to assess wide-area impact, as opposed to 20 V/km estimate when only storm peaks were considered in the 2012 NERC GMD interim report.
Yes
The white paper on the justification for the 15 A threshold is based on published measurements. This is a prudent and conservative approach. Manufacturer-calculated values can vary widely depending on the manufacturer, and at this point in time, few have been validated by measurements. The degree of half-cycle saturation in single-phase units compared to core-type three-limb three-phase units is a matter that will require more study and clarity in the future. The susceptibility of these units to GIC depends strongly on the zero sequence magnetizing impedance of the transformer. The zero sequence magnetizing impedance has an important impact on the level of GIC at which a three-phase three-limb core type transformer will saturate. This parameter is not routinely measured in the factory, but it would be useful for entities to request this information from transformer manufacturers.
Yes
The implementation period provides reasonable timelines.
Yes

Yes
Hardware-based mitigation technologies need to be further proven in test situations before mass deployment.
Yes
The process to decide which shunt compensation elements should be removed is not clear in the GMDTF application guides. The SDT should consider writing a white paper addressing this methodology.
Group
Dominion
Connie Lowe
Yes
Yes
Yes
Yes
Yes
Yes
Yes
R5 Rationale needs to be updated; in which 5.3 needs to be removed. In Part 5.2 ‘Maximum and Amperes’ should not be capitalized, in which they are not defined terms in the NERC glossary. R6/M6 ‘Amperes’ should not be capitalized. Table of Compliance Elements: Page 21 of 24, Lower VSL column, Amperes should not be capitalized Page 21 of 24, Moderate VSL column, Amperes should not be capitalized Page 21 of 24, High VSL column, Amperes should not be capitalized Page 21 of 24, Severe VSL column, Amperes should not be capitalized Page 21 of 24, Moderate VSL column, Amperes should not be capitalized Page 21 of 24, Moderate VSL column, Amperes should not be capitalized
Individual
Frederick
Emprimus
Yes
No
Response to NERC Draft Benchmark GMD Event Description - Under FERC Order 779 By Dr. Frederick Faxvog, Gale Nordling, Greg Fuchs, David Jackson, Wallace Jensen Executive Summary FERC, in Order 779, requires NERC to develop “technically justified” benchmark GMD events upon which utilities will use as a basis to protect their grid. Utilities, NERC, FERC and the professional engineers working for them have a moral, fiduciary and legal obligation to protect the public health, welfare, and customer service through the adoption and implementation of GMD standards that have integrity and that are well vetted by multiple space weather and electric power professionals. NERC is now introducing, in response to FERC Order 779, a new untested and unverified low level benchmark GMD model which greatly reduces the GMD electric field which the utilities need to protect against. This brand new, unvetted theory, absent significant study, peer review and peer consensus, should not be transformed into a standard which is supposed to protect the health and safety of 100’s of millions of Americans. This new model has come up with geo-electric fields that are so much lower than the standards currently for which there is consensus (for a 100 year severe solar storm), that it is being challenged for credibility and reasonableness by many technical experts. This alone should lead one to conclude that a more rigorous peer review and peer

consensus of the model is warranted. This proposed new model could lead utilities to conclude that there is no real threat of damage from GMD, and that they need to do little or nothing additional to comply with it. However when the next significant solar storm hits and significant grid outages occur, and loss of life and substantial financial impact occur, there will be outcry from the public that leads to scrutiny of this model and the process that was used to review it and approve it. The dissenting voices that are skeptical of the incredibly low predicted outcomes of a GMD event will certainly be highlighted in any kind of investigation. We urge caution in considering the adoption of a new standard, without peer consensus, that might be interpreted as self-serving, especially if it is not properly drafted and vetted widely (with consensus) by experienced space science professionals as required by ANSI standards. In addition, the potential lack of protection for customers by using a much lower standard, based upon a completely new unproven and unvetted theory, could expose the utilities to claims. This is another reason to hold a more rigorous review of the model before submitting it for approval. In this paper technical experts at Emprimus who have a corporate focus on protecting the grid from EMP and GMD, have done an analysis of the new NERC benchmark model. The Emprimus conclusions start with identifying the need to do an extensive peer review by space science experts in the GMD community and ensure that the new standards follow the ANSI standards. Additional points include the need to address worst case scenarios versus just addressing the average impacts; the hot spot analysis is not technically justified; the wave form analysis is not technically justified; the "latitude reduction" theory is highly questionable; the assumptions about probability of occurrence of solar super storms are not supported by GMD experts; the known impact to customers and generators from harmonics are not addressed; the substantial increase in grid vulnerability due to power transfers and contingencies has not been taken into consideration; and the magnitude of the impact to customers and national security has not been factored in as a consequence of not getting this standard right. The recent findings by the space weather scientists about the intensity of the July 23, 2012 solar flare eruption should be a wake-up call for all. Professor Dan Baker, Director of the Laboratory for Atmospheric and Space Physics, University of Colorado – Boulder, recently said “I have come away from our recent studies more convinced than ever that Earth and its inhabitants were incredibly fortunate that the 2012 eruption happened when it did. If the eruption had occurred only one week earlier, Earth would have been in the line of fire.” The risks and consequences of doing nothing, which is what would be mandated by this proposed GMD standard, is much higher than the risks and consequences of introducing proven and tested neutral blocking systems into the bulk electric power grid. Technical discussion and support of all of these points is included in following paragraphs. I. GMD Standard is Derived from Weak GMD Disturbances The proposed NERC GMD Standard is derived from recent data that is not representative of a large solar super storm. The storm data considered is from only the last several decades and does not even included the 1989 storm, one tenth the size of a solar super storm, which caused the damage and collapse of the Quebec power grid and also the catastrophic damage to the transformer in Salem, NJ. The potential consequences of a solar super storm are so dire that extreme care should be taken in developing a standard that has large acceptance in both the solar science community and the electrical power industry. Also a standard of this type should be based on many decades of recorded data which exists for example in Northern Europe (60 years of magnetic data) and Japan (89 years of magnetic data). This standard is one that we cannot afford to get wrong. II. New Hot Spot GMD Theory and Spatial Averaging Approach The proposed NERC GMD Standard has introduced a new so called Hot Spot theory which has never been published or vetted in a published paper. It assumes that there will be localized a hot spot of geomagnetic field in an area on the order of 100 by 100 kilometers. This theory cannot be supported for a solar super storm which is known to be thousands of times larger in extent when it hits the earth. There is no reasonable nor logical method to extrapolate data from recent magnetic data (the last several decades) for small storms to conclude that there will be localized hot spots for a solar super storm. Therefore the spatial averaging approach to reduce the GMD standard field from 20 V/km to 8 V/km is not a valid and accepted approach. Hence, the standard field should remain 20 V/km as published in a respected and referred journal two years ago by Pullkinen et. al. (2012). III. Reduction of Standard with Geo Latitude Scaling The reduction of the GMD geo-electric field with geographic latitude cannot be justified with the use of data from weak solar storms as the GMD standard team has proposed. This proposed latitude scaling is a very steep function which may apply for the weak storms considered by the team but cannot be justified for a solar super storm. When the recorded history of the Carrington event shows that Northern lights were observed in Cuba, we cannot conclude that our southern states will not experience nearly the same geo-electric fields as or northern states and Canada. Again, much more care needs to be taken in the development of a latitude scaling function for this GMD standard. IV. Assumed GMD Waveform taken from a Weak Solar Storm The assumed GMD waveform used in the development of this proposed standard is taken from a weak solar storm and most likely does not represent the expected frequency content and sharpness of a solar super storm. It is known that weak solar storms that impact the earth travel at much slower velocities than do solar super storms. Therefore, the sharpness of the waveform of the magnetic disturbance will be greatly enhanced for a solar super storm. This sharpness or frequency content of the wave then relates to the generation of the geo-electric field since the field is directly related to the time derivative of the magnetic field. Hence, the proposed GMD field standard is certainly greatly understated as a result of this assumption in the development of the proposed standard. V. Assumption that Load Shedding and Brown Outs are an Option The GMD standard makes the assumption that to avoid power grid problems during a GMD event it will be acceptable to shed load and/or create brown outs to avoid grid voltage collapse and equipment damage. To our knowledge there are no other scenarios in the industry where load shedding is permitted. Additionally, since the space weather predictions/warnings from NOAA or other agencies are by no means 100% accurate, there could be a number of GMD events which simply do not couple effectively into the earth's fields, such that many times impacts to the grid are minimal and load shedding would not be warranted. Finally, it would be highly unlikely that a utility would endorse a load shedding policy in light of potential customer litigation in cases where a GMD event did not couple effectively into the grid. VI. Potential for Component Damage by GMD Produced Harmonics The proposed GMD standard does not adequately cover the potential for component damage to equipment, such as generators, SVCs and capacitor banks, by even moderate GIC currents that produce harmonics in half-cycle saturated transformers. While the potential for harmonic damage is briefly referred to, the proposed standard gives no guidance for harmonic levels that could cause damage. And the standard gives no guidance on how to analyze a network for this issue. VII. Probability of a Solar Super Storm Impacting the Earth Again The draft of this GMD standard quotes only one paper by J. F. Love which implies that the probability for a solar super storm is not very large (6.3% within the next 10 years). However, the standard drafting team should also quote several other papers on this topic which show the probabilities for a solar super storm as 12%, 13% and 14.7% within the next 10 years. These papers are by P. Riley (2012), R. Katakoa (2013) and R. Thorberg (2012). And these predictions extrapolate to a 50% probability within the next 50 years using the standard Poisson process. By all accounts this is a very high probability especially when the consequences of such a storm will be so paralyzing to our society and our way of life. It is know now recognized that solar super eruptions do not occur every 50 or 100 years from the sun but in fact erupt on average every 7.5 years. The difference is that many such super eruptions do not hit the Earth but instead travel outward in other directions. As an example the solar flare eruption of July 23, 2012 is now recognized as a solar super eruption. Professor Daniel Baker of the University of Colorado recently stated "In my view the July 2012 storm was in all respects at least as strong as the 1859 Carrington event, the only difference is it missed." VIII. More Solar Weather Scientists Needed on the Standard Development Team The entire reduction of the geo-electric field standard from 20 V/km down to 8 V/km has been driven by only one solar weather scientist on the standard drafting team. Since this standard is so critical to our country, society and our existence, the drafting team should have included at least six if not more solar scientists on the team. The decision to limit the size of the drafting team for expedience or any other reason is a dangerous approach. And there exist many other noted and experienced solar scientists that would never agree with the methods used to develop this proposed standard. IX. Lack of a Safety Margin in the Proposed Standard In most industries there are safety margins that are built into standards and requirements. Typically safety margins are on the order of 3 to 5 times the largest load that might expected. In this case, since we are attempting to predict the geo-electric field of a solar super storm that has only occurred in 1859 and 1921 before modern measurement equipment, we should mandate that a safety margin be applied to the mean prediction of 20 V/km by Pullikenen et. al. (2012). So with a safety margin of say 3 times this mean prediction, the standard should be 60 V/km, not 8 V/km as proposed by the drafting team. X. Potential for Hidden Assumption that Mitigation will be Expensive It appears likely that the team has may have concluded that mitigation achieved with equipment will be prohibitively expensive. The extreme opposite is in fact the case, the equipment, a neutral blocking system, is very inexpensive, uses off the shelf components and has been built, extensively tested and demonstrated in a live grid at Idaho National Laboratories. Independent studies by both the University of Manatoba and by EPRI show that the

introduction of neutral blocking systems will not cause any unintended consequences for typical power grids. These studies have been made available to the industry within the last year. The equipment for one neutral blocking system is on the order of $300k with an installation cost of $50k or less. Studies performed by PowerWorld LLC for the state of Wisconsin and the state of Maine indicated that adequate protection of a states grid can be achieved with neutral blocking systems on about 50% of the HV and EHV transformers. The cost of this protection is estimated to be a $2 onetime charge per customer. Additionally, when a utility uses noneconomic dispatch whenever NOAA predicts a K7 or larger solar storm, the price of electric is increases since more expensive generation is purchased to avoid outages. But when neutral blocking systems are in place, this noneconomic dispatch procedure can be avoided. So it is estimated that under these conditions neutral blocking systems will provide a pay-back with 1 to 2 years. Hence, neutral blocking systems will reduce costs, provide a cost pay back within a few years and then reduce costs thereafter.
No
The GMD standard does not adequately consider transformers with tertiary windings which makes these transformers more vulnerable to GIC currents and subsequent heating.
No
We do not support the implementation plan schedule as it is entirely too long. The probability of a solar super storm is agreed to be about 12% within the next 10 years. And state of the art power flow modeling with GIC modules now show that a solar super storm will generate GIC currents of 500 to 3,000 amps in many networks. And these currents levels have the potential to create the largest catastrophe known to mankind. Therefore, the proposed timeline for this implementation plan should be streamlined down to two years or less.
No
Typically safety margins are on the order of 3 to 5 times the largest load that might expected. In this case, since we are attempting to predict the geo-electric field of a solar super storm that has only occurred in 1859 and 1921 before modern measurement equipment, we should mandate that a safety margin be applied to the mean prediction of 20 V/km by Pullikenen et. al. (2012). So with a safety margin of say 3 times this mean prediction, the standard should be 60 V/km, not 8 V/km as proposed by the drafting team.
No
It appears that the team (SDT) may have concluded that mitigation achieved with equipment will be prohibitively expensive. The extreme opposite is in fact the case, the equipment, a neutral blocking system, is very inexpensive, uses off the shelf components and has been built, extensively tested and demonstrated in a live grid at Idaho National Laboratories. Independent studies by both the University of Manatoba and by EPRI show that the introduction of neutral blocking systems will not cause any unintended consequences for typical power grids. These studies have been made available to the industry within the last year. The equipment for one neutral blocking system is on the order of $300k with an installation cost of $50k or less. Studies performed by PowerWorld LLC for the state of Wisconsin and the state of Maine indicated that adequate protection of a states grid can be achieved with neutral blocking systems on about 50% of the HV and EHV transformers. The cost of this protection is estimated to be a $2 onetime charge per customer. Additionally, when a utility uses noneconomic dispatch whenever NOAA predicts a K7 or larger solar storm, the price of electric is increases since more expensive generation is purchased to avoid outages. But when neutral blocking systems are in place, this noneconomic dispatch procedure can be avoided. So it is estimated that under these conditions neutral blocking systems will provide a pay-back with 1 to 2 years. Hence, neutral blocking systems will reduce costs, provide a cost pay back within a few years and then reduce costs thereafter.
No
Group
FirstEnergy Corp
Richard Hoag
Yes
Yes

Yes
Yes
Yes
Yes
No
Group
Tacoma Public Utilities
Joe Wilson
Yes
Yes
Yes
Yes
Yes
Yes
Yes
There is a potential gap in data sharing because the standard lacks a requirement for Planning Coordinators to share GDM modeling data with neighboring Planning Coordinators or with regional entities. Particularly within the western interconnection, many Planning Coordinators have a small geographic footprint but the GMD analysis requires a regional model. We suggest modifying either the applicability section or requirement R1 to include the either the Regional Entity, the Regional Entity's designee, or the Reliability Coordinator as possible responsible entities for maintaining GIC system models. Some entities have not shared GIC modeling data such as latitude and longitude data because of concern over sharing potential Critical Energy Infrastructure Information per FERC order 630. We would support the STD providing guidance on appropriate sharing of modeling data, including latitude and longitude to two or more decimal places.
Individual
Brenda Hampton
Luminant Energy Company, LLC
Yes
We do not have enough information to effectively evaluate this methodology.
Yes
Yes
While it is unclear how these performance requirements affect a GO, many factors should be considered when developing a mitigation plan. Table 1 is not clear in how it applies to a GO. Costs should be balanced with risk in any mitigation plan. If implemented as written, the standard could

allow for a TP to mandate that a GO purchase multiple spare transformers separate and apart from any consideration of costs or risks for the generating unit.
Yes
(1) In order to obtain the thermal response of the transformer to a GIC waveshape, a thermal response model is required. To create a thermal response model, the measured or manufacturer-calculated transformer thermal step responses (winding and metallic part) for various GIC levels are required. A generic thermal response curve (or family of curves) must be provided in the standard or in the attached documentation. Without the curve, the transformer evaluation cannot be performed. The reference curves and other needed data should be provided for review prior to ballots on this standard. (2) How will entities determine if their transformers will receive a 15 Amperes GIC during the test event? (3) It seems like the requirements as written will not incorporate well into a deregulated market with non-integrated utilities. For instance, a TP or PC could instruct a GO to purchase new equipment or shut down their generating unit. This could potentially introduce legal issues in a competitive market. The standard should be revised to eliminate these unintended consequences.
Group
SERC Planning Standards Subcommittee
David Greene
No
Is it the intent of the SDT that the entity evaluate the GIC impact of each transformer for each orientation of the Benchmark GMD events (for every 15 degrees from 0 to 90 degrees), and perform a powerflow analysis based on the additional Mvar losses identified for each orientation of the Benchmark GMD event? If so, please add these details to the reference material and to the Application Guideline for R3.
Yes
no comment
No
Detailed modeling data needed to assemble the initial DC models may be problematic for some entities. We are very interested in obtaining the Transformer Modeling Guide, as details to be discussed therein are needed to be able to use our recently obtained GIC module software. One data parameter in this software, a 'K' factor, is needed to be specified correctly in order to correlate GIC current with transformer reactive power losses, which is the entire point of this entire exercise. Errors in specifying this factor on each affected transformer would have a significant impact on the validity of the entire assessment. While the period for producing the models has been increased from 12 months to 14 months in the Implementation Plan, we are still concerned about meeting this time frame.
Yes
Yes
Yes
Comment 1: R4 should be modified to allow for future developments in determining voltage stability during a severe GMD event. Specifying steady-state voltage limits as the performance criteria for voltage stability requires that a power flow analysis be performed. Although this is an acceptable approach, in the future more sophisticated methods of determining voltage stability may prove to be better suited for GMD vulnerability assessment. Thus, we recommend modifying R4 as follows: Suggested Wording 1: R4. Each Planning Coordinator and Transmission Planner shall have criteria for determining voltage stability of its System during the GMD conditions described in Attachment 1. Comment 2: The use of load shedding and/or curtailment of Firm Transmission Service to meet performance criteria should be allowed. The reasons for this are two-fold: 1) the intent of the GMD vulnerability assessment is to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System and 2) the probability of the GMD event occurring is 1-in-100 years. Therefore, we recommend modifying #4 in Table 1 as follows: Suggested Wording 2: 4. Load

loss as a result of manual or automatic load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Load loss or curtailment of Firm Transmission Service is minimized. Comment 3: The GIC capability of our transmission transformers has not been something typically specified as part of transformer purchases. For any transformers we own for which the GIC value is determined to be 15 A or greater, it will be necessary to contact the transformer manufacturer to determine whether the transformer could withstand the GIC. This situation will likely lead to transformer manufacturers being inundated with requests for such information from all North American TOs. In addition, obtaining such information for transformers whose manufacturer is out of business would be an additional difficulty. Is it the intent of the SDT that the Vulnerability assessment process would be that a new assessment would not be required for the addition of a new EHV line addition, EHV transformer, or replacement of an existing EHV transformer? The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
John Seelke
Public Service Enterprise Group
Yes
Yes
Yes
Yes
No
In R7, the responsible entities in R1, which is “Each Planning Coordinator, in conjunction with each of its Transmission Planners,” develop a CAP in response to performance deficiencies identified by them in R3. However, the PC/TP does not have any NERC authority to require any entity to implement the actions in its CAP. That said, the PC/TP may have separate authority outside of NERC such as a FERC-approved RTO/ISO tariff or by agreement with such entities. So that R7 is clear in this regard, we request the first sentence in R7 be modified to recognize this fact. We suggest the following addition to R7: “Responsible entities as determined in Requirement R1 that conclude through the GMD Vulnerability Assessment conducted in Requirement R3 that their System does not meet the performance requirements of Table 1 shall develop a Corrective Action Plan addressing how the performance requirements will be met; PROVIDED, HOWEVER, THAT SUCH RESPONSIBLE ENTITIES MAY ONLY REQUIRE OTHER ENTITIES TO IMPLEMENT THE CAP PLAN AS IT AFFECTS SUCH OTHER ENTITIES’ FACILITIES BY AUTHORITY GRANTED TO SUCH RESPONSIBILIE ENTITIES BY SEPARATE PRIOR TARIFF OR AGREEMENT.”
No
Individual
Michelle D'Antuono
Ingleside Cogeneration, LP
Yes
Ingleside Cogeneration LP (ICLP) agrees that it is the initial responsibility of the Planning Coordinator and/or Transmission Planner to identify transformers that may be vulnerable to GMD. They have the system models and simulation engines that can best make that determination. Once the PC/TP analysis is complete, only those GOs and TOs who own susceptible components will be responsible for a comprehensive thermal analysis – again a sensible expectation. After all, it is in the owner’s best interest to protect valuable equipment if there is a tangible threat posed by GMD.

Conversely, those located in areas that are not at risk should not be required to spend scare dollars and resources preparing for a very low-probability event.
Yes
ICLP believes that the best knowledge available to the industry has been used to develop GMD benchmarks and planning criteria. We expect corrections will be made as actual event data is accumulated and compared to simulation results.
Yes
Again, ICLP believes that the best knowledge available to the industry has been used to develop the criteria for thermally-susceptible transformers. As a result, we cannot offer a better GIC current threshold at this time. However, we would like to see NERC commit to a process where the set of identified components is evaluated for consistency. It is of clear interest if one planning entity returns results significantly different than one located in a comparable region. Reliability is best served if ALL at-risk transformers are identified, while those not-at-risk are not. ICLP suspects it will take several iterations of comparative studies before that level of precision can be reached.
Yes
Yes
Yes
The transformer owners will be motivated by economic self interest to mitigate a GMD threat – as long as they have confidence in the planning simulation results. Therefore, it is critical for NERC to find a way to verify actual performance against the computer models. ICLP is aware that it is not easy to record and validate the effect of geomagnetically induced currents on the BES, but the effort is worth it. With other major threats like cyber security looming, the industry needs to allocate scarce resources addressing those which pose the greatest risk to electric service continuity.
Individual
Oliver Burke
Entergy Services, Inc.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Greater flexibility should be provided for transmission planners to account for system changes or modifications that may impact GMD assessment during or after the five year period assessments. In Table 1 on page 8 of TPL-007-1, NERC's Standard Drafting Team should consider the limits associated with modeling the impact of harmonics on protection system trips, it may not be possible to identify all disconnected equipment in planning simulations. An alternative would be to model the impact of harmonics on a case by case basis by modeling the area of interest in detail with EMTP-type programs.
Group
Seattle City Light
Paul Haase

Yes
Seattle City Light appreciates the effort of the drafting team to respond to FERC's requests and address industry input. Many concerns have been addressed, but Seattle has remaining concerns in two areas. (1) Use of the Planning Coordinator (PC) to conduct studies: this may be appropriate in most regions but is not appropriate in WECC, which has approximately one-half of all NERC registered PCs. As such, many PCs (such as Seattle) are small and focused only on local considerations. While we could conduct the studies required by proposed TPL-007 on our PC area, the results would not be particularly meaningful because they would address only the area around the city of Seattle. An alternative approach that allows aggregated studies in WECC would be more effective, either at the regional (PEAK RC) or subregional (Northwest Power Pool) levels. (2) Seattle is concerned with the frequency of the studies. A 60-month cycle seems frequent for entities such as Seattle that do not change composition or configuration. We suggest a 120-month cycle for entities that can demonstrate stable system size.
Individual
David Thorne
Pepco Holdings Inc
Yes
Yes
Yes
Yes
Yes
No
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Requirement R3: The GMD Vulnerability Assessment (GMDVA) is currently written to cover the Near-Term Transmission Planning Horizon, which means the GMDVA will cover the 12-60 month time period from the date of the GMDVA. However, since the GMDVA is only required every 60 months, the next GMDVA can technically be at 60 months. This means that the efforts to mitigate GMD effects for the year immediately after the second GMDVA (e.g., from 60-72 months) will have little time to be implemented. While it is expected that in the early years (e.g., 0-24 months) of the implementation of this standard there will be little time to implement mitigating activities, the results of the second and later GMDVAs should allow more time to mitigate newly discovered issues. Allowing the GMDVA completion schedule to be the same as the time period it covers may result in reduced reliability, since using the period just after the later GMDVAs does not allow sufficient lead time for mitigation. This can be remedied by either reducing the time period between GMDVA completions (once every 36 months while retaining the Near-Term Transmission Planning Horizon coverage) or increasing the time covered by the GMDVA (96 months instead of the five-year Near-Term Transmission Planning Horizon for the time period covered by a GMDVA that is required every 60 months). Texas RE requests the SDT consider revising the language so the completion schedule is less than the time period it covers. Requirement R4: Texas RE requests the SDT explain what it envisions as establishment of an “acceptable limit” to be (as indicated in Table 1, Steady State item d.) when voltage collapse “shall not occur” (as indicated in Table 1, Steady State item a.). As written, it appears the limit is allowed to be just before the voltage knee where collapse occurs. This would not lend itself to determining compliance for this requirement and may interject reliability issues. In addition, the rationale states that the voltage levels may be different than TPL Standards. Having different voltage level requirements may cause issues with TPL compliance and possibly with reliability. The SDT may want to consider additional language, either within the text of the requirement or an application guideline, to coordinate the acceptable GMD steady voltage limits with the generation undervoltage relay settings requirements in PRC-024 and UVLS systems. Requirements R5 and R6: As written, Requirement R5 and R6 only require one performance of the Requirement (providing geomagnetically-induced current (GIC) flow information and conducting a thermal impact assessment, respectively). The responsible entities will only need to perform the actions in those Requirements once to be compliant. It is unclear whether the SDT intended this result. Texas RE asserts that both requirements need to be performed periodically (i.e., every 60 months, in concert with the GMD Vulnerability Assessment) in order to have a reliability benefit to the BES. Texas RE recommends adding a sub-requirement addressing recurrence. Requirement R7: Requirement R7 does not address completion of a Corrective Action Plan (CAP), only that it be reviewed in subsequent assessments (every five years) until the system meets performance requirements in Table 1. This allows for the possibility that a CAP could go on for extended periods with no conclusion. The third bullet under R7.1 implies that a CAP will have dates for accomplishing the changes needed by including the dates that the Operating Procedures can be eliminated. However, there is no enforceable requirement that needed changes to the BES will be done at specific times. While issues and dates will change with each new set of studies, a CAP for a GMD issue should have dates and/or triggers for each action needed. For example, the corrective action ‘add a GMD tolerant transformer at the substation’ may not be accomplished if it does not have a due date or trigger to accompany it. Without a completion requirement, enforcement cannot act even when there is a demonstrable reliability risk to the BES. Texas RE suggests the SDT consider adding a trigger such as “when n-1 situations cause excessive loading of the current transformer” or a date such as 2020. The trigger might also be a combination of the two: “when n-1 situations cause excessive loading of the current transformer or 2020, whichever comes first.” Compliance Monitoring Process, Section 1.2 Evidence Retention: If evidence retention for responsible entities is five years, it could be difficult to demonstrate compliance. A CAP may take longer than five years to complete. This puts a burden on the entity to “provide other evidence to show that it was compliant for the full time period since the last audit.” Texas RE recommends the SDT revise the retention language to state responsible entities shall retain evidence on CAPs until completion. The limited evidence retention period also has an impact on determination of VSLs. Determining when the responsible entity completed a GMDVA will be difficult to ascertain if evidence of the last GMDVA is not retained. Texas RE recommends revising the evidence retention to cover the period of two GMDVAs.
Group
JEA
Tom McElhinney

Individual
David Jendras
Ameren
No
We believe that additional clarification is required for the GIC process, and ask about the intent of the standard drafting team to: a. Evaluate the GIC impact of each transformer for each orientation of the Benchmark GMD event (for every 15 degrees from 0 to 90 degrees), and b. Perform a powerflow analysis based on the additional Mvar losses identified for each orientation of the Benchmark GMD event? If so, we request the drafting team add these details to the reference material and to the Application Guideline for Requirement R3.
No
(1) We believe that the Benchmark Geoelectric field amplitude of 8 V/km is overly conservative for a 1 in 100 year occurrence, and a safety margin of 25 percent as reported on page 14 of 27 of the Benchmark GMD Event is too much. (2) A GMD event of 4-5 times the magnitude of the1989 Quebec event as the basis for the 1 in 100 year storm is perplexing, given the few “high magnitude” events that have occurred over the last 21 years. From our perspective, the requirements to provide mitigation for these extreme GMD events are not supported.
No
The Screening Criterion for Transformer Thermal Impact Assessment document cites several instances where transformers all rated 400 MVA or less are exposed to GIC currents to determine their thermal response. However, the predominant rating for transmission transformers on our system is 560 MVA or larger. We ask if these transformers in general are to be expected to withstand greater than 15 A before reaching a 50 degree C temperature rise?
No
(1) Detailed modeling data needed to assemble the initial DC models is as yet not fully available. We are very interested in obtaining the Transformer Modeling Guide, because accurate details are needed to be able to confidently use our recently obtained GIC module software. (2) One data parameter in this GIC software, a ‘K’ factor, needs to be specified correctly in order to correlate GIC current with transformer reactive power losses, which is the entire point of this entire exercise. Errors in specifying this factor on each affected transformer would have a significant impact on the validity of the entire assessment. (3) While the period for producing the models has been increased from 12 months to 14 months in the Implementation Plan, we are still concerned about meeting this time frame.
Yes
No
We believe that this standard, as proposed, would direct all PCs and TPs to perform a large amount of effort to put together the necessary DC GIC models to come to the conclusion that they need not take any significant action for a GMD event.
Yes
The GIC capability of our transmission transformers has not been something typically specified as part of transformer purchases. For any transformers we own for which the GIC value is determined to be 15 A or greater, it will be necessary to contact the transformer manufacturer to determine whether the transformer could withstand the GIC. These situations will likely lead to transformer manufacturers being inundated with requests for such information from all North American TOs. In addition, obtaining such information for transformers whose manufacturer is out of business would be an additional difficulty. The performance requirements described in the definition, in the background, and in Table 1 are not clear and appear to be conflicting. (See Table 1 steady state performance requirement a, b, and d.) For additional reactive load losses and outage of capacitor banks caused by GIC, how would load be lost except for voltage collapse? We believe that the emphasis should be placed on widespread voltage collapse and not simply local voltage collapse issues that may occur for equivalent Category C type of events. Our understanding of the Vulnerability assessment process would be that a new assessment would not be required for the addition of a new EHV line addition, EHV transformer, or replacement of an existing EHV

transformer. We believe that details for performing the calculations and assessments are still being developed, and are in its infancy at this stage, and are far too early to codify into a standard.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
No
The percentage basis for R6 strongly affects small entities. A GO with five transformers which are identified receives a severe VSL for completing four of five; a larger entity with one hundred transformers can miss on fourteen and get a high VSL. The impact to the BES is much greater for the larger entity, but the VSL is not. Suggest adding "for entities with fewer than ten identified transformers" and making one failure a medium VSL, two a high, more than two severe.
Yes
R7.3 states the CAP should be provided to 'adjacent Planning Coordinators, adjacent Transmission Planners,'. A GO does not have the wide area view to determine which PCs and TPs would be impacted by the CAP. The requirement should be to provide the CAP to the RC, who can then determine which entities need the information. The requirement should also include giving notice to the GO or TO that the CAP has been sent to those adjacent PCs ans TPs, and provide the CAP owner with the names of the PCs and TPs along with contact information.
Group
Colorado Springs Utilities
Kaleb Brimhall
Yes
No Comments
No
We have concerns over the lack of maturity in the understanding of the theoretical foundation and execution of the evaluation process. What pilot evaluations have been completed to vet this process with the selected event? We would recommend rolling this process out in a pilot format to refine it and ensure that we are getting the desired evaluation that improves reliability prior to wholesale enforcement. Pilots would need to be conducted in various geographical areas and companies. Then results would be compared and processes refined to reach our reliability goals. Wholesale enforcement of a process that has not been fully vetted will expend precious resources without getting us where we need to go. Understandably the pilots would need to be expedited much like the CIP version 5 standards. With a pilot vetting the process and providing better guidance we could shorten the implementation plan to make-up time expended during pilots and best utilize industry resources.
Yes
No Comment
No
If we do not perform a pilot we recommend that R2 implementation be pushed out to 24 months. This will require evalution and procurement of software in addition to the gathering and input efforts required to build the model in the software. R5 and R6 should be moved as well to correspond to the extended timeframe of R2, as recommended above. Is R2 the “dc System Model referenced in the flow chart”?
No

Historical evidence does not demonstrate that any of the VRFs should be “high.” Evaluation may be prudent, but potential risk has not proven this to be a high risk to reliability. A pilot would better demonstrate actual risk.
No
SPP Comments only
Yes
We have concerns over the lack of maturity in the understanding of the theoretical foundation and execution of the evaluation process. What pilot evaluations have been completed to vet this process with the selected event? We would recommend rolling this process out in a pilot format to refine it and ensure that we are getting the desired evaluation that improves reliability prior to wholesale enforcement. Pilots would need to be conducted in various geographical areas and companies. Then results would be compared and processes refined to reach our reliability goals. Wholesale enforcement of a process that has not been fully vetted will expend precious resources without getting us where we need to go. Understandably the pilots would need to be expedited much like the CIP version 5 standards. With a pilot vetting the process and providing better guidance we could shorten the implementation plan to make-up time expended during pilots and best utilize industry resources.
Individual
Rich Salgo
NV Energy
Group
Bureau of Reclamation
Erika Doot
Yes
Yes
Yes
Yes
The Bureau of Reclamation (Reclamation) appreciates the drafting team’s efforts to design a phased approach for completing transformer thermal impact assessments and Corrective Action Plans. Reclamation continues to suggest that R6 should include a 60-month timeframe like R2. As written, it is not clear how often Generator Owners and Transmission Owners are required to conduct thermal analyses of qualifying transformers.
No
Reclamation does not believe that R6 should carry a high VRF. Reclamation believes that the failure to conduct a thermal impact assessment in a timely manner would not likely have a direct impact on the bulk electric system. Therefore, in accordance with the NERC Rules of Procedure and Sanction Guidelines, Reclamation believes that the VRF should be lowered to low or possibly medium.
No
As written, R7 could be interpreted to allow Planning Coordinators and Transmission Planners to determine Corrective Action Plans without any input or buyoff from Transmission Owners and Generator Owners who may have to bear costs and operational changes associated with corrective actions. Reclamation continues to request that the drafting team include an additional requirement that Planning Coordinators and Transmission Planners to demonstrate that agreement has been reached regarding proposed actions, costs, and timeframes for actions in a Corrective Action Plan that will be completed by Transmission Owners or Generator Owners.
Yes
Reclamation continues to suggest that R6 should include a 60-month timeframe like R2. As written, it is not clear how often Generator Owners and Transmission Owners are required to conduct thermal analyses of qualifying transformers. Reclamation also continues to request that the drafting team clarify why Reliability Coordinators are not included within the scope of the standard. The

Question and Answer document did not clarify the rationale for this decision. In the Western Interconnection, the inclusion of the Reliability Coordinator would ensure an interconnection-wide perspective on transmission planning for geomagnetic disturbance events.
Group
Duke Energy
Michael Lowman
Yes
Yes
Yes
Yes
Yes
Yes
No
Duke Energy would like to commened the SDT on the work they have done on this project and would like to state that we believe this version of TPL-007- 1 adequately addresses FERC's directives in a way that could be accepted by the industry.
Individual
George H. Baker
James Madison University
No
No
I have grave concerns about the methods used to calculation of geoelectric fields. See comments under question 7.
Yes
No
The four-year timeline should include implementation of corrective action.
No
The standard is so weak that VRFs and VSLs are meaningless.
No
Standard should prescribe mitigation strategies to facilitate uniform protection against GMD.
Yes
Comments on NERC's draft GMD Benchmark Report I have grave concerns about the validity of NERC's April 2014 "Benchmark Geomagnetic Disturbance Event Description" report and wish to alert you to major technical problems with its contents. Because of significant flaws in the report, the GMD Benchmark Event should not be approved in its present form. Re-investigation and revision is needed. The text of my letter below speaks to major concerns. I have also included an attachment that provides specific comments by paragraph based on my review and methods of 'extreme event' probability expert, Dr. Charles T. C. Mo. To begin with, the NERC report misuses available statistics on solar storm environments. The report employs an incomplete data base that uses a 20 year time window to make inferences about the probability of 100 year effects. In effect, the report assumes the sun behaves the same during all solar cycles, an assumption known to be erroneous. The report bases its conclusions on subjectively extrapolated tails of probability distributions using incomplete data sets. This methodological error effectively closes the door on preparedness for "outlier" storms

such as the 1869 Carrington event or the 1921 Railroad Storm. The NERC report contains no reference to or rationale for dismissing measured geoelectric fields and GIC data that are far in excess of what the GMD Benchmark would predict. Statisticians often assess risk using a number called "expected loss," which is derived by multiplying the probability of an accident times the value of the loss caused by the accident. This approach is implicit in NERC's concern about reducing the probability of a major GMD event— viz. by using a 20 year interval of relatively mild solar storms, and reducing the expected loss by minimizing the expected 100 year peak electric field, and by inventing the concept of limited-area solar storm electromagnetic "hot spots." A prudent person would base decisions involving high consequence events on factors that go beyond the expected loss. A better approach for low-likelihood, high consequence events has been developed by Professor Yacov Haimes at the University of Virginia. In his "Partitioned Multi-Objective Risk Method" or PMRM approach , Haimes argues that it is necessary to account for catastrophic events separately from ordinary accidents. Rare but extreme loss catastrophes may have a manageable expected loss, but that does not mean that accepting their risk is justified.[i] As an illustrative example, a catastrophe involving a 100 year Carrington-class solar storm could conceivably shut down the U.S. economy for 1 year or more. The value of the economic loss would be one GNP or approximately 17 trillion dollars. If the probability is 1% per year (the historic probability is in this ballpark), the expected loss would be $170 billion, which is relatively small in comparison to the annual U.S. federal budget. But the PMRM approach would argue that because hundreds of millions of lives are at risk and because continuity of national governance is at risk, such a catastrophe must never be allowed to happen. In summary, even though a Carrington Event-caused shut-down of a continental-scale portion of the North American electric power grid is unlikely in any single year, it is also totally unacceptable. Based on Professor Haimes' arguments and other reasons, I submit that the entire North American grid should be protected against GMD if FERC and NERC are serious about safeguarding the American public. Reasons include: 1. Uncertainties in magnitude of worst-case GMD fields are at least a factor of ten. Southerly latitudes may well be exposed to much larger GMD than predicted by the NERC standard de-rating formula. 2. Protective measures are commercially available and cost-effective. Neutral current blocking devices can accommodate a factor 5-10 excursion in the field magnitude above the NERC 8 KV bogey proposed in the draft standard. 3. The entire North American grid is susceptible to exposure to the effects of a nuclear EMP E3 that outstrips the NERC 8 KV bogey by a factor of 10. Nuclear E3, unlike GMD, increases at southerly latitudes. In the event of a nuclear EMP event, portions of the grid unprotected against GMD will succumb to EMP-E3 effects. It is highly prudent and cost-effective to address EMP-E3 and GMD protection concurrently – otherwise another highly redundant and unnecessary round of costly protection assessment and implementation will be required. In closing, we need to be very careful where the survival of millions of Americans and the breakdown of our national governance is at risk. There is reasonable certainty that GMD storms and EMP events will occur with magnitude in excess of the Benchmark GMD Event. These high-magnitude events will render moderate protection designed to a defective GMD Benchmark completely ineffective. Implementation of the current draft GMD Benchmark will leave us susceptible to continental-scale grid failures from solar GMD and EMP. I recommend that NERC incorporate Yacov Haimes' PMRM approach to protect our society. Finally, I urge you to send the current Benchmark Geomagnetic Disturbance Event Description document back to the Standard Drafting Team for revision. Sincerely, George H. Baker Professor Emeritus and Former Director, Institute for Infrastructure and Information Assurance, James Madison University Congressional EMP Commission Attachment: Detailed comments on Project 2013-03 Benchmark Geomagnetic Disturbance Event Description Attachment 1 NERC Project 2013-03 Benchmark Geomagnetic Disturbance Event Description Detailed Comments George H. Baker and Charles T.C. Mo o Page 6, paragraph 4. Do you include all data in the 100 year time span? If not, another layer of statistical inference is needed based on a model that includes the sampling nature of the known data vs. the actual occurrences. The analysis must based on all available data and objectively and truthfully exclude any subjective data truncation. o Page 6, formula (1). An added factor is needed to account for shoreline enhancement. Many generator stations and associated transformers are located along edge of water bodies. o Page 7, paragraph 1, sentence 1. Should include data going back as far as possible even if 100 year span is not available. Look for and include data from outlier events. o Page 7, paragraph 2. ♣ The latitude scaling was not explained in the earlier formula (1) discussion. Is this just a cosine law or empirical? Show the relation curve and error range. ♣ The 8kv/m level is lower than historically measured peak GMD field values. ♣ You need to add the approximate low frequency formula that maps dB/dt to E|| including its dependence on earth

conductivity and effective ground depth. o Page 9, Statistical Considerations, paragraph 1. ♣ You dismiss the Carrington event from the data base since there is inadequate information to relate dB/dt to E field. You made no mention of the 1921 Railroad Storm where dB/dt levels. Data from this storm will be very important to include since it was a high-side outlier. o Page 9, Statistical Considerations, paragraph 2. ♣ Explain why you see a correlated relationship between DST and storm strength. ♣ Again, why have you not referenced the 1921 Railroad Storm? ♣ Per your statement, “These translate to occurrence rates of approximately 1 in 30-100 years,” please include the confidence level or Bayesian coverage if a subjective Bayesian formulation is used. Also, you need to explain the "translate" model, e.g. do these events have Poisson independent arrival times of constant rate, or what? In any case, extrapolating from a 20 year data base to 600 years assumed a strong stationarity of the event occurrences. Proper statistical inference from such events needs be accompanied by a reduced confidence since the extrapolated time span is significantly longer than the data time window. o Page 10, Figure I-1. Please provide a reference for this figure. Where in the refereed professional journals have you seen the “hot spot” concept developed? o Page 11, paragraph 1 and figure I-2. You need to convince the reader/user. How do these four 10.0 to 18.9 year coverage curves infer complete 100 year behavior? o Page 11, Figure I-2. Behavior of the tails of these distributions is not shown. Extreme values of the low end of probabilities are subject to large uncertainties. o Page 12, Paragraph 1. The fundamental flaw of following the 20 year model fit regression type statistical analysis (and thus claim to infer from one cycle the sunspot behavior of many other cycles and accordingly infer solar behavior over a much longer time span) is that your approach assumes that the model parameters are actually the same set of constants in all cycles. As a result, your estimates and inferences from data in just one solar cycle, or in two cycles is equivalent to expanding them to represent one much larger data set, i.e., you are assuming parameters computed based on one cycle immediately valid for any other cycle. But if these parameters are themselves random sample realizations from cycle to cycle, then the analysis is totally invalid. As an extreme example: if within one 11 year cycle you have a very large sample set, then you can estimate these parameters with near certainty in a almost point value estimate. But then you have no information of their value in another cycle. Realistically, you must physically model these parameters as random variables themselves, such that each cycle contains a parameter set of their realization. Then use these sets to develop your estimates. The proper approach is mathematically more complicated but a physically more realistic two layer statistical inference problem. o Page 12, Figure I-3. The sample time window is too narrow to infer 100 year behavior. o Page 16, paragraph 1. Not clear how the intensification factor of 2.5 was derived. Please explain and provide reference. o Page 16, Figure I-6. It is important to take into account where the locus of transformers within the grid. If the transformers are positioned at choke points, the loss of small number can be significant.
Group
Tennessee Valley Authority
Brandy Spraker
Individual
Dan Inman
Minnkota Power Corporative
Yes
No
See NSRF Comments
Yes
No
See NSRF Comments
Yes
Yes

Yes
The Definition in TPL-007-1 for Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment refers to “voltage collapse, Cascading or localized damage of equipment.” In Table 1-Steady-State Planning Events refers to “Cascading and uncontrolled islanding shall not occur.” Why are they different?
Individual
Mark Wilson
Independent Electricity System Operator
Yes
No
The SDT has made a significant contribution by defining a GMD benchmark event but further steps in the process need more clarity. We do not agree the approach described in TPL-007 will allow planning decisions to be made with an acceptable level of confidence. We suggest the following process would provide an acceptable level of confidence: 1) Determine vunerable transformers using the benchmark event and simplified assumptions (e.g. uniform magnetic field and uniform earth) and screen using the 15A threshold to determine vulnerable transformers. 2) Install GIC neutral current and hot spot temperature monitoring at a sufficient sample of these vunerable transformers. 3) Record GIC neutral current and hot-spot temperature during geomagnetic disturbances. 4) Refine modelling and study techniques until simulation results match measurement to within an acceptable tolerance. 5) Use the Benchmark event with the refined model to evaluate a need for mitigating actions. Comments from the SDT on this procedure would be received with great interest.
Yes
We agree the proposed 15A threshold is a conservative screening threshold. Some transformers in Ontario experienced higher GIC levels than 15A/phase during the 1989 event with no material long-time adverse effects.
No
We believe that the proposed timeframe and sequencing in the implementation plan is stringent. GMD modeling data is not commonly available as other data types reported in current MOD standards. Furthermore, entities need to acquire the new models. Requirement 1 should be 90 days, Requirement R2 should be 24 months, R5 should be 36 months and Requirements R3, R4 and R7 should be 60 months.
Yes
No
We do not think the SDT has gone far to remove uncertainty that will adversely affect cost/benefit analysis. For example, the following caveats applied to the GIC capability curve method make it almost difficult for this technique to provide an acceptable level of confidence in a planning decision: “While GIC capability curves are relatively simple to use, a fair amount of engineering judgment is necessary to ascertain what portion of a GIC waveshape is equivalent to, for instance, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves have to be developed for every transformer design and vintage .” To promote a consistent application across the interconnection, the SDT should provide more guidance on how to achieve an acceptable level of confidence that mitigating actions are needed. A process to arrive at this level of confidence is presented in our response to Question (2).
Yes
To balance the risk of transformer damage with the risk to reliability if transformers are needlessly removed service; the standard should require Generator and Transmission Owners to select a thermal analysis technique acceptable to Transmission Planners and Planning Coordinators. This is necessary to mitigate a risk that asset owners would gravitate towards simple but overly-conservative techniques that would result in too much equipment removed from service.
Individual
Venona Greaff

Occidental Chemical Corporation
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
The NSRF agrees that the steps in the revised draft for TPL-007-1 address concerns about the organization of the standard. We would like to commend the SDT for paying attention to the recommendation of stakeholders by developing the flowchart and a process that is sensible and easy to follow.
No
The NSRF has a concern in reference to how and when we should use the Beta value in scaling the geoelectric field. Per the discussion at the July Technical Conference, it was suggested that “engineering judgment” should be used in this process. However; the standard suggest ‘For large planning areas that cover more than one scaling factor from Table 3, the most conservative (largest) value for β should be used in scaling the geoelectric field.’ We would like to see more clarity on how Beta should be used in the calculation process and suggest implementing the term ‘engineering judgment’ into the standard. Also, we are concerned that data in Table II-2 (Geoelectric Field Scaling Factors) may not be accurate for all regions located in the IP1 earth model. The Benchmark GMD Event is represented by the SHIELD region on Figure II-3: Physiographic Regions of North American and the Geoelectric Field Scaling Factor is 1.0. The one reading for the IP1 earth model is measured relatively close to the SHIELD and the scaling factor is 0.94. However the IP1 model includes a very large portion of the US map. The NSRF believes that this scaling factor is inappropriate and is not representative of all the US regions included in the IP-1 earth model particularly the lower parts of the region such as the state of Iowa that exhibits low resistivity that the 0.94 scaling factor is clearly too high. We recommend that the Scaling Factors be reviewed for accuracy, compared to actual readings, etc. and be refined prior to being included as a reference.
Yes
No
The NSRF does not agree with the proposed implementation plan for Requirement R1. We believes that 60 days is not enough time to identify the individual and joint responsibilities of the PC and each of the TPs in the PC’s planning area for completing the activities in R2, R3, R4, R5, and R7. Some PCs will require a CFR document that will need to be reviewed and signed by the TP’s management. In our experience with CFR documents, the process requires at least 6 months to complete. Also, the implementation plan as currently proposed, requires the GMD Vulnerability Assessment and Corrective Action Plan to be completed in 48 months. A Corrective Action Plan is to be developed only if the entity’s GMD Vulnerability Assessment, conducted in R3, results in a System that does not meet the performance requirements of Table 1. If the entity needs 48 months to complete its GMD Vulnerability Assessment in Requirement R3, there will not be enough time to complete the Corrective Action Plan in Requirement R7. We suggest that the SDT revise the implementation plan for Requirement R7 to be completed after the GMD Vulnerability assessment.
Yes
Yes
Yes
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes

Yes
Yes
Yes
Yes
Yes
Yes
R4 should be modified to allow for future developments in determining voltage stability during a severe GMD event. Specifying steady-state voltage limits as the performance criteria for voltage stability requires that a power flow analysis be performed. Although this is an acceptable approach, in the future more sophisticated methods of determining voltage stability may prove to be better suited for GMD vulnerability assessment. Thus, we recommend modifying R4 as follows: R4. Each Planning Coordinator and Transmission Planner shall have criteria for determining voltage stability of (Remove “acceptable System steady state voltage limits for”) its System during the GMD conditions described in Attachment 1. The use of load shedding and/or curtailment of Firm Transmission Service to meet performance criteria should be allowed. The reasons for this are two-fold: 1) the intent of the GMD vulnerability assessment is to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System and 2) the probability of the GMD event occurring is 1-in-100 years. Therefore, we recommend modifying #4 in Table 1 as follows: 4. Load loss as a result of manual or automatic load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be (Remove “needed”) used to meet BES performance requirements during studied GMD conditions. (Remove “but should not be used as the primary method of achieving required performance.”) GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Load loss or curtailment of Firm Transmission Service is minimized (Remove “during a GMD event”).
Individual
Gul Khan
Oncor Electric LLC
Yes
No
The map in figure 1 on page 13 of the standard has BETA values that are very broad. We have a concern in reference to how and when we should use the BETA value. The standard suggests on page 12 “for large planning areas that cover more than one scaling factor from Table 3, the most conservative (largest) value for β should be used in scaling the geoelectric field.” We recommend that engineering analysis be used for a more accurate distribution of the entities area since Oncor falls in between 2 different beta values of ip4 (0.41) and cp2 (0.95). We recommend the term “engineering analysis” be added to the standard itself similar to as in FAC-008 requirement 1.1. (Per the July NERC Technical Conference presentation, slide 104 suggests the use of engineering judgment. We would like to apply that here as well.
Yes
No
Regarding R6 we are required to complete the thermal assessment on our transformers within 12 months of obtaining our manufacturer provided GIC capability curves. Since this is dependent on the number of transformers on our system, 12 months may not be enough time to complete the assessment. We kindly request the extension of this period to 24 months. Additionally not being able to influence the time period it will take to obtain our manufacturer GIC capability curves can

lengthen the time it takes to complete R5. We recommend that the implementation period for R5 be extended from 18 months to 24 months.
Yes
Yes
Yes
Oncor commends the SDT for providing the 15A threshold which allows flexibility for transmission planners from assessing unnecessary equipment. However for the equipment that must be assessed there are a few items that, as mentioned in our response to question 2, can better equip us for performing our study.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
No
Introducing a minimum GIC figure for thermal assessment is an improvement, but it is recognized in the industry that single-phase transformers, such as are generally used on 500 kV-and-up generator step-up transformers (GSUs), are much more susceptible to geomagnetic disturbances (GMDs) than are the three-phase GSUs used at lower voltages. It therefore appears that separate min-GIC values should be specified for single-phase and three-phase equipment.
1. The Rationale for Requirement R6 states that “The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means.” Regarding the first of these alternatives, we (and probably most other entities) have no manufacturer capability curves for geomagnetically-induced current (GIC), nor would it be reasonable to expect that such information will ever be made available for equipment that was designed and manufactured in most cases decades ago. NERC’s Transformer Thermal Impact Assessment white paper states for the second alternative (simulation), “hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers,” which are unavailable as stated above, or, “Conservative default values can be used (e.g. those provided in [4]) when specific data are not available.” Reference 4 is an IEEE technical paper by Marti et al, and it shows transfer functions, “as determined by the manufacturer,” for a single-phase transformer (“Transformer A”) in Fig. 1 and as determined during acceptance testing for another single-phase unit (“Transformer B”) in Figure 5. There are no “conservative default values” presented for three-phase transformers, nor any suggestion that the Transformer A and B curves can be applied with confidence for all single-phase equipment. The Transformer B information is in fact unusable, since the unit operated for only one minute at a GIC level above the TPL-007-1 screening threshold value of 15 A. The “e.g.” in the Transformer Thermal Impact Assessment white paper citation above means “for example,” indicating that sources of conservative default values other than the Marti paper may be used. None are listed in the References section of the white paper, nor do we know of any open literature containing a wide-ranging database of this information. Scattered bits and pieces may be found, such as the examples shown in NERC’s GMD publications, but these collective inputs are greatly inadequate given the statement in the white paper that “manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves have to be developed for every transformer design

and vintage.” Thermal impact assessment via simulation is therefore not a viable option, leaving only, “other technically justified means.” The Transformer Thermal Impact Assessment white paper provides no indication of what such means may consist-of, nor are we able to imagine any. Special sensors such as those evidently applied when testing Transformer B of the Marti paper could not be installed for equipment in the field, nor would testing of every transformer in North America prove practical. NERC’s Geomagnetic Disturbance Planning Guide of Dec. 2013 states that one can use, “defaults [transfer functions], such as the ones shown in the NERC Transformer Modeling Guide, but this document has never been issued. There is in summary no practical means of achieving compliance with R6 of TPL-007-1. We recommend that NERC obtain conservative default GIC curves covering all types and sizes of transformers affected by this standard, and then publish this information in the promised Transformer Modeling Guide.
Group
DTE Electric
Kathleen Black
No Comment
No Comment
No
If special software is required by the transformer owner to perform the thermal assessment using the supplied GIC waveform, then examples of software should be provided in the white paper. It would be beneficial to have more detail concerning the thermal assessment and transformer thermal response model analysis.
No
R6.4 indicates that the thermal impact assessment needs to be performed and provided to the responsible entities within 12 months. This is unrealistic based on the analysis required. 36 months, at minimum, would be a more reasonable time frame. Also, it should be clarified that only mitigation recommendations are expected with the assessment.
No comment
No
More clarity is needed on who selects and funds GIC mitigation measures resulting from the thermal impact assessment.
Yes
The scope of facilities included should be limited to BES transformers connected at 200kV or higher. Transformers excluded from consideration (instrumentation, station service) should be mentioned in the standard with a clear definition of these types provided. Are the transformer owner's suggested mitigations per R6.3 incorporated into the Corrective Action Plan per R7? It is not clear how thermal assessment results are reviewed and mitigated.
Individual
Richard Vine
California ISO
Individual
Teresa Czyz
Georgia Transmission Corporation
Yes
GTC agrees that the flowchart addresses the steps for the overall assessment process. We would like the SDT to consider adhering to the current BES definitions for facilities. As non-BES facilities could be subjected to this standard.
Yes
Yes
No

Consideration needs to be given to the fact that the majority of entities to which this standard applies will need to “build” a DC model for their own system and then merge the model with other entities in order to create a “DC model of the system”. Many entities do not have the expertise or knowledge in building such models and entities may not have adequate resources or software to accomplish this task within the time frame posed. GTC recommends extending the timeline to 8 years in order to ensure the completeness and accuracy of the “DC model of the system” and to complete the assessment.
No
GTC disagrees with the SDT’s assignment of VRFs with this standard, and believe the levels should be assigned based on the risks of GICs within geographical latitudes.
Yes
No
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
No
The 8 V/km benchmark event is at the upper end of the range of probable 100 year events. This will help assure that the industry is prepared for GMDs however, it may prove to be financially wasteful to the majority of the industry. Instead the industry should prepare for the median value from a 100 year event. Further, the NERC GMD team has provided Earth Resistivity Region maps that would be helpful to determine the β scaling factor to apply the benchmark event to our region, but those USGS derived maps do not include the majority of our service territory. The areas missing are the Northern, Middle and Southern Rocky Mtns and the Wyoming Basin. Tri-State’s service territory of 200,000 square miles is right in the middle of these four undefined areas. Tri-State would appreciate guidance from NERC on how these area’s will be handled in the future.
Yes
Tri-State agree with the 15 A/phase GIC threshold for now based on existing analysis, but urge the NERC GMD Advisory group to finalize and issue the “Transformer Modeling and Testing” project and report. Tri-State believes that if this report is based on additional empirical data then it may verify a higher GIC threshold. Also, this report may help significantly with the analysis needed to estimate the GIC caused thermal changes and harmonics levels. The IEEE standard C57.91 recommended by NERC covers only the estimation of loss-of-life for various overload and high temperatures, but does not provide guidance on calculating the effect of GICs.
No
Although the changes are an improvement to the standard, Tri-State still believes it may not provide an adequate amount of time for completion. Estimating the harmonics, transformer heating and VAR losses may be more complicated and time consuming. Considering the whole industry will be looking to get information from a limited number of sources the high demand; this may cause the process to move slowly, taking much longer for analysis to be completed than is given by the current implementation plan. Tri-State also believes the effective date for Requirements R3, R4, and R7 should be aligned with the 60 calendar month review time frame. Since R3 states there should be an assessment completed every 60 months, the effective date for R3 should also be 60 months.
Yes
Yes
Yes
Tri-State believes R6 requiring each TO and GO to conduct a thermal impact assessment for each jointly owned applicable transformer would be a duplicative and unnecessary requirement. This will

require multiple analysis of jointly owned facilities and will be a waste of resources for entities. Tri-State suggests the operators be in charge of running the thermal impact assessment and sharing that to all the appropriate owners. TOs and GOs should be responsible for acknowledging that they received the assessment and keeping for the required period of time. This would significantly reduce the number of assessments completed while keeping the goal of the requirement.
Individual
Joe Tarantino
Sacramento Municipal Utility District
SMUD advocates for the GMD study requirements be performed or optioned for conducting the studies at a Regional level or as part of a Task Force or a Working Group for the following reasons: • Regional level developed model will provide a better considered analysis than by the individual PCs, TOs, or GOs; • Study results will be better analyzed and interpreted by equipment owners instead of individual entities' interpretation of the results; • A single report produces for all Regional members instead of individual report from each Members could lead to inconsistent results/conclusions/recommendations; • Entities' resources can be significantly reduced by participating in Regional process instead of perform the numerours studies that are currently contemplated in the standard.
Group
SPP Standards Review Group
Shannon V. Mickens
Yes
No
We have a concern in reference to how and when we should use the Beta value in scaling the geoelectric field. Per the discussion at the July Techincal Conference, it was suggested that 'engineering judgement' should be used in this process. However; the standard suggest 'For large planning areas that cover more than one scaling factor from Table 3, the most conservative (largest) value for β should be used in scaling the geoelectric field.' This seems contradictory to what was expressed at that Technical Conference. We would like to see more clarity on how Beta should be used in the calculation process and suggest implementing the term 'engineering judgement' into the stardard.
Yes
No
We have a concern in reference to Requirment R1 and the 60 calendar day time frame. The concern would be not having enough time to determine which entities and responsibilities should be assigned to. The level of communication may have complexity and we would like the language to account for that in the process if possible. We would respectfully request a time extension to 6 months. Our second concern would be in reference to Requirment R6 and the 36 calendar month time frame. Our concern would be working with older equipment (example transformers)…. the retrieval and evaluation of data. Also, there is a concern in reference to the GMD Assessments specifically the harmonics and evaluating this data as well. We would respectfully request extending the time frame to 42 calendar month time frame.
Yes
No

Our concern in reference to Mitigation Costs associated with the applicability section ‘4.2.1 Facilities that include power transformer(s) with high side, wye-grounded winding with terminal voltage greater than 200 kV.’ One concern would be how the term ‘ Facilities’ are used in this section. Currently, we can assume that transformers are the main topic of discussion. As we look more to the future, other ‘equipment/Facilities’ may begin to be included into the process but not specifically defined. We would like to see more specifics on what type of ‘equipment/Facilities’ that would be defined and associated with this standard. This clarification would give us a better handle on managing our Mitigation Costs.
Yes
In the description of Facilities in the revised standard, the SDT deleted the ‘a’ in ‘…with a high side wye-grounded winding…’It would seem that with the ‘a’ deleted the following term ‘winding’ should be plural. In fact, that is just what the SDT did in the 4th line of the Summary paragraph in the Screening Criterion for Transformer Thermal Impact Assessment document. Under Applicable Facilities in the Implementation Plan the ‘a’ is omitted and ‘winding’ is singular. In the 1st line at the top of Page 7 in the Project 2013-03 (GMD Mitigation) TPL-007-1 Common Questions and Responses the SDT reverts back to the use of ‘a’ in the facilities description. Further down the page the ‘a’ is omitted. Regards of which way the SDT decides to go with this phraseology, the SDT should be consistent throughout all documents. Throughout the document, the SDT needs to be consistent with the treatment of 30-, 60- or 90-calendar days by hyphenating the phrase. This also applies to the use of 12- and 36-calendar months. In Requirement R5, use a lower case ‘maximum in the 3rd line of Part 5.2. The SDT should capitalize Part throughout the standard and documentation when referring to requirements. In the 2nd line of the 2nd paragraph under Justification in the Screening Criterion for Transformer Thermal Impact Assessment, insert ‘°C’ following ‘110’.
Individual
Russell Noble
Public Utiltiy District No. 1 of Cowlitz County, WA
Cowlitz defers to the Planning Coordinators and Transmission Planners.
Cowlitz defers to the Planning Coordinators and Transmission Planners.
Yes
Cowlitz does not have the expertise to offer substantive opinion. However, we agree with a conservative approach until a greater knowledge base is developed.
Yes
However, this is uncharted territory. There should be provision to deal with any unanticipated difficulties.
Yes
Yes
Cowlitz can’t envision a need to require entities to find the most cost effective means to address the performance requirements of the Standard. However, it is possible that footnote 4 of Table 1 is not descriptive enough. Cowlitz believes that the performance requirements may need recovery and maximum outage duration metrics included. For low occurrence, high impact events, localized temporary outages must be tolerated to avoid intolerable power costs. This is very difficult to define, but is it out of the question to require limits on local outages? Ultimately, Cowlitz agrees with the method, and cautions against overly descriptive performance requirements.
Yes
For smaller entities who lack experienced modeling engineers, the guidance and white papers are high level and very difficult to grasp if not impossible. Contract engineering consultant work will be a must, however a basic understanding of key concepts would be a great help in assuring the procurement of good engineering expertise. Cowlitz suggests a white paper addressing this would be most helpful.
Individual
Terry Harbour
MidAmerican Energy
Yes

No
MidAmerican is concerned that data in Table II-2 (Geoelectric Field Scaling Factors) may not be accurate for all regions located in the IP1 earth model. The Benchmark GMD Event is represented by the SHIELD region on Figure II-3: Physiographic Regions of North American and the Geoelectric Field Scaling Factor is 1.0. The one reading for the IP1 earth model is measured relatively close to the SHIELD and the scaling factor is 0.94. However the IP1 model includes a very large portion of the US map. This scaling factor is inappropriate and is not representative of all the US regions included in the IP-1 earth model particularly the lower parts of the region such as the state of Iowa that exhibits low resistivity that the 0.94 scaling factor is clearly too high. MidAmerican recommend that the Scaling Factors be reviewed for accuracy, compared to actual readings, etc. and be refined prior to being included as a reference.
Yes
No
MidAmerican does not agree with the proposed implementation plan for Requirement R1. Sixty (60) days is not enough time to identify the individual and joint responsibilities of the PC and each of the TPs in the PC's planning area for completing the activities in R2, R3, R4, R5, and R7. Some PCs will require a CFR document that will need to be reviewed and signed by the TP's management. In our experirece with CFR documents, the process requires at least 6 months to complete. Also, the implementation plan as currently proposed, requires the GMD Vulnerability Assessment and Corrective Action Plan to be completed in 48 months. A Corrective Action Plan is to be developed only if the entity's GMD Vulnerability Assessment, conducted in R3, results in a System that does not meet the performance requirements of Table 1. If the entity needs 48 months to complete its GMD Vulnerability Assessment in Requirement R3, there will not be enough time to complete the Corrective Action Plan in Requirement R7. We suggest that the SDT revise the implementation plan for Requirment R7 to be completed after the GMD Vulnerability assesement.
Yes
Yes
Yes
MidAmerican is concerned that the requirement to analyze the harmonic impacts on relaying when no such methods are resonably available is burdensome. Prior to finalizing the standard the SDT should provide guidance on how to do this or, at least, what should be considered as compliant with this requirement.
Individual
Eric Olson
Transmission Agency of Northern California
Group
ISO/RTO Council Standards Review Committee
Greg Campoli
No
Further reorganization is needed. The steady state voltage limits for the System during the benchmark GMD event that responsible entities are required to have under R4 is needed to conduct the GMD Vulnerability Assessment. Accordingly, we suggest that R3 be moved down to become R4 and R4 be moved up to become R3. R1 and R2, in essence, require the development of the necessary models needed to perform the vulnerability assessments. The obligations under those requirements fall on the PC and TPs. However, those functions need data from the equipment owners (GOs and TOs) to develop the models. The standard needs to ensure those entities are obligated to provide the data for this purpose. This can be done in the context of these requirements, or, alternatively, via a stand alone requirement or subrequirement. This data would need to be provided within 90 days of the request, or other agreed to time period. In ISO/RTO regions, compliance with NERC standards is often achieved by performance with regional rules (e.g. ISO/RTO tariff or protocol requirements). Accordingly, M1 should accommodate this approach to

demonstrating that the necessary coordination has occurred (i.e. “each Planning Coordinator in conjunction with each of its Transmission Planners”) with respect to assigning the relevant responsibilities. Footnote 1 from NUC-001 may be informative for this purpose. Specifically, FN 1 states: 1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.
Yes
Yes
No
The SRC offers the following comments on the implementation plan. There seems to be a disconnect between the Standard and the Implementation Plan for R1. The implementation plan calls for R1 to be effective 60 days following the approval of the Standard, while the Standard states that the effective date is 12 months following FERC approval. Please modify/clarify what the SDT intends. Is the intent that is it effective 60 days after the 12 month period after FERC approval or just 60 days following FERC approval? In considering clarifications regarding this issue, the SDT should ensure that the time frame for complying with R1 is adequate to facilitate an effective and efficient outcome. Coordinating all relevant entities for this purpose and reaching agreement on the assignment of responsibilities is not a trivial task and appropriate time has to be allowed to accomplish this. The SRC recommends that 4 months be allowed to comply with R1. For R2, having its effective date on the first day of the first calendar quarter that is 14 calendar months after the date that the standard is approved may not be feasible. We suggest 18 calendar months after the date that the standard is approved. Another issue that needs to be addressed is the proper sequencing of the relevant actions under the different requirements. Establishing an appropriate sequence to the actions is required because certain obligations (e.g. planning assessments) require inputs from the outputs of other obligations. For example, the criteria for acceptable voltage limits (R4) is needed in order to conduct the GMD Vulnerability Assessment (R3), and the GMD Vulnerability Assessment needs to be completed in order to have the GIC flow information to provide to the GOs and TOs (R5) so they can do their thermal impact assessments (R6). This involves multiple entities. To ensure the relevant actions under the requirements is coordinated and funtions effectively and efficiently, the SRC recommends the SDT revise the Standard accordingly, and offers the suggested changes to the Implementation Plan: For R3 (complete GMD Vulnerability Assessment), change the implementation timeframe from 48 months to 30 months. For R4 (have criteria for acceptable steady state voltage limits during benchmark GMD event), change the implementation timeframe from 48 months to 30 months. For R5 (provide GIC flow info to TOs & GOs for their transformer thermal impact assessments), change the implementation timeframe from 18 months to 30 months. For R6 (GO & TO conduct thermal impact assessments based on values provided in R5), change the implementation timeframe from 36 months to 42 months.
Yes
Yes
Yes
A. Page 1 – “Description of Current Draft” should state that this is the second draft (not the first draft). B. Page 3, Section 4.2.1 - change “Facilities that include power transformer(s)…” to “Power transformer(s) – power transformers are the only concern. C. Page 5, M3 - the current language is inconsistent with Part 3.3 of R3. To make it consistent, the phrase “any functional entity who has indicated a reliability related need” must be changed to “and any relevant information shall also be provided to any functional entity that submits a written request and has a reliability related need,” which are the words use in Part 3.3 of R3. Similar comment applies to M7 (similarly inconsistent with Part 7.3 of R7- see comment H below. The SRC recommends adding “any relevant information” to give the responsible entities discretion to effectively manage the dissemination of the information in a vunerability assessment and/or corrective action plan (see comment on R 7.3 below). That information may be sensitive from a reliability (and potentially market) perspective and should be managed accordingly. By adding “relevant” to this obligation, the responsible entities can provide the necessary data to requesting entities based on need, while limiting access to other sensitive

data. D. Page 6, Rationale for Requirement R4 - change “may by different” to “may be different” (typo). E. Page 6, M5 - change “provided geomagnetically-induced current (GIC) flow information” to “provided GIC flow information” (GIC is defined earlier in the Standard, so the acronym can be used here). F. Page 6, Rationale for Requirement R5 - change “The GIC flows provided by part 5.2 and 5.3 are used” to “The GIC flows provided by part 5.2 are used” (5.3 has been deleted). G. Page 6, Requirement R6 – a provision that requires the TO and GO to provide the results of the thermal impact assessment to the applicable PC/TPs should be added. H. Page 7, M6 - change “as specified in Requirement R6” to “as specified in requirement R6 and have evidence that it provided the thermal impact assessment to entities in accordance with 6.4” I. Page 7, Requirement 7.3 - CAP could call for action by a Transmission Owner (TO) or Generator Owner (GO), therefore 7.3 should be expanded to require provision of the relevant information in the CAP to the TO or GO that has been identified as being required to take action under the CAP. Change “and to any functional entity that submits a written request and has a reliability related need” to “and any relevant information shall also be provided to any other functional entity referenced in the Corrective Action Plan or that submits a written request and has a reliability related need.” J. Page 8, M7 – change “and to any functional entity who has indicated a reliability related need” to “and to any functional entity that is referenced in the Corrective Action Plan or that has submitted a written request and that has a reliability related need to receive the information.” K. Table 1 states that Protection Systems may trip due to effects of harmonics and that the analysis shall consider removal of equipment that may be susceptible. The standard should identify the appropriate entity(ies) to determine if this will occur, and require those entities to provide that information to the entities that are performing the relevant analyses. The SRC believes this determination likely rests with the equipment owners.
Individual
Bill Fowler
City of Tallahassee
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes
Yes
No
BPA believes the implementation plan for R1 is too short. BPA’s experience in implementing TPL-001-4 R7 suggests coordination takes more than two months to identify the facilities and determine joint or individual responsibility and have an agreement in place to comply with the standard for a large system like BPA. BPA suggests a minimum of six months.
Yes
Yes
Yes
Table 1, Footnote 4 indicates that load loss should not be used as a primary method of achieving required performance. BPA requests clarification on the primary method. Would Under Voltage Load Shedding (UVLS) be considered a primary method? This event is an extreme event and if assessments show that UVLS schemes would be triggered to prevent voltage collapse, BPA believes this should be allowed. In addition, Table 1 “Category” column indicates GMD Event with Outages. Does this mean the steady state analysis must include contingencies? If so, what kind of contingencies: N-1, N-2, …..? If not, BPA requests clarification of the category of GMD Event with Outages. Finally, BPA reiterates our comments from the informal comment period: BPA feels that the current state and maturity of transformer modeling does not provide modeling which is

universally available for all transformers, and less available (if at all) for older transformers that are not of a current design, as would be manufactured today.
Individual
Angela P Gaines
Portland General Electric Company
Yes
Portland General Electric appreciates the efforts of the drafting team in developing this standard. However, our primary concern is that in the WECC due to the size of the region, the RC should be included as an applicable entity since they would have the wide area view of the region and could better facilitate the coordination of studies and reviews amongst entities.